ALASKA North Slope Spills Analysis

Final Report on North Slope Spills Analysis and Expert Panel Recommendations on Mitigation Measures

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FINAL REPORT

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EXECUTIVE SUMMARY

The goal of the North Slope Spills Analysis is to reduce the frequency and severity of future spills from North Slope crude oil piping infrastructure integrity loss. The North Slope Spills Analysis represents a continuation of efforts begun in 2008 to conduct the Alaska Risk Assessment (ARA), which was proposed as a quantitative risk assessment of North Slope crude oil infrastructure to consider, among other factors, whether the age of the North Slope oil infrastructure was a significant causal factor contributing to oil spills.

The North Slope Spills Analysis investigates risks to Alaska's crude oil infrastructure by compiling available spill data, identifying causal factors, and analyzing the trends in loss-of-integrity spills from crude oil piping infrastructure on the North Slope. Loss-of-integrity spills were defined as a failure that leads to a reportable spill of any fluids in the production stream, including mechanical failures and human errors. The analysis was limited to North Slope oil production infrastructure, which includes wells and associated piping, flowlines, process centers with their associated piping and above ground storage tanks, and crude oil transmission lines.

This analysis considers the frequency, severity, and causes of North Slope oil spills by regulatory category and oil field, and provides recommendations to the State of Alaska to reduce the frequency and severity of future spills. The analysis utilized available data from spills reported to the Alaska Department of Environmental Conservation (ADEC) from North Slope oil production operators during the period of July 1, 1995 to December 31, 2009. ADEC spill data was supplemented by additional review of publicly available documentation and reports, and in some cases, verified by the operators. An Expert Panel was convened to review the analysis and provide recommendations about potential risk reduction measures that address the relationship between causal factors and infrastructure characteristics.

A spills database was constructed consisting of 640 loss-of-integrity spills from the North Slope oil production infrastructure. These data were investigated by regulatory category and oil field using a number of different metrics, such as frequency of spills, severity of spills, primary cause of failure, as well as temporal and spatial trends. The analysis also considers leak rates, pipeline age at failure, leak detection, and impacts. Analyzing spill frequency, severity, and cause of spills provides a means to identify and understand problems with the goal of making corrections where needed and reducing the frequency and severity of future spills. Although this study was limited by some missing data, and the dominance of a few very large spills in the data set, several notable findings were observed.

The frequency of loss-of-integrity spills across all of the oil fields and regulatory categories from the North Slope oil and gas infrastructure shows no significant trend over the analysis time period. There is some evidence that the severity of spills trends upward over the study period, but due to the non-normal data distribution, this trend is not considered statistically significant.

For the six regulatory categories analyzed (flowlines, oil transmission pipelines, facility oil piping, process piping, wells, and above-ground storage tanks), the analysis shows some notable differences in the relative contributions of spills from different categories. Spills from flowlines account for the highest total amount of oil spilled of the six regulatory categories. The average spill volume for flowlines is twice the average of all spills. Facility oil piping, process piping and wells all contribute significantly to the frequency of spills, yet proportionally less to the volume spilled. Spills from above ground storage tanks represented the second lowest spill frequency; however a storage tank spill was the single largest spill in the data set. Spills from oil transmission pipelines have been rare, however one of these spills, caused by internal corrosion, caused the second largest spill in the data set.

Causal analysis from loss-of-integrity spills where cause was recorded shows that valve/seal failure is the most frequent cause of all spills, but corrosion is the most frequent cause of spills greater than 10,000 gallons. External corrosion is the dominant cause of flowline spills.

Calculating leak rates that control for production volume or pipeline mileage allows comparison between oil fields and can serve as a benchmark for future comparison. Volumetric leak rates vary dramatically because of the few very large spills. Numeric production leak rates are more consistent and show that leak rates for Colville River - Alpine, Endicott, and Northstar oil fields are consistently lower than for Kuparuk River, Milne Point, and Prudhoe Bay. Overall, Endicott appears to have the lowest overall leak rates, and Milne Point has the highest rates. The Prudhoe Bay and Kuparuk River oil fields experience very similar leak rates. Badami oil field was excluded from this comparison because of sparse and erratic data.

The relationship between pipeline age and the frequency and severity of spills from that infrastructure was a major concern of the Alaska legislature. The data collected for pipeline age at failure was inconsistent across oil fields, but for those pipeline leaks where age at failure was known, there appeared to be a significant correlation between pipeline age and probability of leaks. The model predicts that a 5 year old pipeline has a 3.3% probability of having a spill, while a 30 year old pipeline has a 31% probability of having a spill.

Limited data available on leak detection methods used and time required to detect spills supports the hypothesis that reducing the time-to-detection for spills on the North Slope could dramatically reduce spill severity. The predominant detection method of loss-of-integrity spills was visual. No reported spills were detected solely by leak detection systems. Statistical analysis of the data for periodicity showed that the maximum number of spills were detected in June, and this supports the fact that visual leak detection is the predominant means of detection, since June is the month with the longest period of daylight hours, coupled with diminished snow cover that makes visual leak detection more effective.

Insufficient data was available to detect trends in spill impacts, and the North Slope Spills Analysis does not attempt to analyze potential or actual consequences of loss-of-integrity oil spills. Such analysis may be a logical next step.

Based on the data alone, it appears that measures for reducing spill frequency would be most effective for facility oil piping, process piping, and wells, while measures for reducing spill severity should focus on flowlines.

Upon reviewing the data presented in this report and considering information provided from regulators and operators, the Expert Panel identified seven recommendations for reducing the risk of future loss-of-integrity spills from North Slope infrastructure. These recommendations are presented in order of priority, with the highest priority assigned to those recommendations the Panel considered to be most proactive in addressing future risks.

1. Move to an integrated Integrity Management Program that focuses on leading indicators.

2. Adopt or model IMP components at State level and for flowlines and require documentation of IMP-like activities for flowlines.
3. Utilize existing and emerging technologies to reduce the time required to detect pipeline leaks.
4. Standardize and improve spill data collection in order to better assess trends and common causes of spills so that prevention measures can be targeted and evaluated to reduce future leaks.
5. Conduct regular and ongoing proactive risk analyses to maintain systems at a prescribed level of safety, and share information from risk analyses among operators and with regulators.
6. Oversee implementation of corrective or preventive measures to evaluate their impact and effectiveness.
7. Establish a system of escalated enforcement to enhance and increase regulatory attention on operators that have spills on the North Slope.

Commonalities exist between the Expert Panel recommendations, which were developed based on early analysis of the North Slope Spills data, and other comments and recommendations compiled earlier in the Alaska Risk Assessment project. Common themes included the need for enhanced field assessments and infrastructure inspections, the need to improve data collection and access to industry information, and the importance of ongoing risk analysis and forward-looking risk management activities.

More effective management of the spill risks and trends identified in this analysis, both at the operator and the agency oversight levels, can result in a reduction to the frequency and severity of spills due to loss-of-integrity from North Slope crude oil infrastructure.

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INTRODUCTION 1

The North Slope Spills Analysis represents a continuation of efforts begun in 2008 to conduct the Alaska Risk Assessment (ARA), which was proposed as a quantitative risk assessment of North Slope crude oil infrastructure. The Alaska State Legislature funded the ARA project in 2007 with the goal of conducting a broad, systematic assessment of oil and gas infrastructure. The ARA project was initiated in 2008 using a phased approach. Phase 1 included hiring a contractor, conducting initial outreach and project scoping, developing a database of the existing oil and gas infrastructure, and developing a methodology to implement the quantitative risk assessment (Alaska Department of Environmental Conservation 2008, http://www.dec.state.ak.us/spar/ipp/ara/documents.htm, April 2010).

Upon completion of Phase 1 of the Alaska Risk Assessment, the State of Alaska determined that the methodology proposed for the ARA could not be effectively implemented and would not provide an analysis that satisfied the legislative mandate for the project. Instead of implementing the quantitative ARA methodology, the State of Alaska developed an alternative approach – the North Slope Spills Analysis – that would assess the frequency, severity, and causes of past spills, and then develop risk mitigation recommendations to reduce the frequency and severity of future oil spills.

This report documents the project background, methodology, data analysis, and recommendations of the Alaska North Slope Spills Analysis.

1.1 Statement of Problem

The Alaska oil industry intends to continue crude oil production from North Slope oil fields using the existing crude oil infrastructure for another 50 years (Bailey, 2006) (Pemerton, 2006). Additional recovery of crude oil using the existing infrastructure maximizes the return on investment, provides a continued and substantial revenue stream for industry and State government, and avoids the impact of developing new areas. Critical to the success of ongoing production from these existing fields is the ability to continue reliable and safe operation of the infrastructure.

In the past decade, there have been a number of significant pipeline spills on the North Slope, which highlighted the vulnerability of the infrastructure to leaks, breaks, and loss-of-integrity. The 2006 GC-2 Oil Transit Line release, which occurred when small holes in a corroded oil transmission pipeline discharged an estimated 212,000 gallons of crude oil to the tundra, was the largest pipeline spill to date on the North Slope. In late 2009, three North Slope pipeline spills suggested the possibility of systemic problems with the integrity of North Slope crude oil pipeline infrastructure. An initial review of North Slope spill history showed that the overwhelming majority of oil spilled (both in terms of spill events and total quantity spilled) was from the pipelines that transport oil, gas, and produced water (ADEC 2003).[1] The North Slope Spills Analysis was initiated to analyze the cause of past spills with the goal of reducing the frequency and severity of future spills that may result from similar causes.

1.2 Project Goal

The goal of the North Slope Spills Analysis is to reduce the frequency and severity of future spills from North Slope crude oil piping infrastructure integrity loss. The project was initiated by the Alaska Department of Environmental Conservation (ADEC) during 2010 to investigate risks to Alaska's crude oil infrastructure by identifying available spill data, identifying causal factors, and analyzing the trends in loss-of-integrity spills from crude oil piping infrastructure on the North Slope.

In 2007, when the Alaska Legislature originally allocated funding for this project, one of the legislative directives was to analyze whether the age of the North Slope oil infrastructure was a significant causal factor contributing to these spills. The North Slope Spills Analysis does consider whether spill trends over time suggest any relationship to infrastructure aging, while also looking for other trends in historic spill occurrences that could be linked to future prevention activities.

1.3 North Slope Oil and Gas Production Infrastructure

1.3.1 Brief Overview of North Slope Oil Development

Alaska changed dramatically with the discovery of North America's largest oil field at Prudhoe Bay on the Arctic coast in 1967. In the early 1970s, as petroleum production from the contiguous US states entered a decline, a new discovery of oil at Prudhoe Bay on the North Slope of Alaska offered the country the promise of a significant new source of competitive domestic supply. Oil production from Alaska's North Slope began in 1977. Exploration in the area led to a series of other major discoveries in the vicinity of the initial discovery, several of which also rank among the largest in North America, and which themselves gave rise to a sequence of new development. Oil production increased to 2.2 million barrels per day by 1988, representing 25% of the U.S. domestic production. By 2005, production had declined to below 900,000 barrels per day, representing about 17% of the U.S. domestic production. Production has since declined to below 630,000 barrels per day in 2009, but still represents about 13% of the U.S. domestic production (U.S. Energy Information, July 2009, http://www.eia.doe.gov/basics/quickoil.html, June 2010).

All oil production to date has been from fields in the Central Arctic (Colville-Canning area) on state lands and adjacent waters of the Beaufort Sea (The Northstar Unit produces from both state and federal waters in the Beaufort Sea). Through 2004, Alaska North Slope oil fields had produced 15 billion barrels of oil, or about 70% of the estimated economically recoverable oil from the currently developed fields.

On the North Slope and in the adjacent Beaufort and Chukchi Seas, there are more than 4,800 exploratory and production wells, 223 production and exploratory drill pads, over 500 miles of roads, 28 production plants, gas processing facilities, seawater treatment plants, power plants (National Research Council 2003), and approximately 989 miles of flowline and oil transmission pipelines.

1 This trend was noted in the 2003 ADEC "Statewide Summary of Oil and Hazardous Spill Data, Fiscal Years 1996-2002: Provisional Report," which showed that 83% of spills, accounting for 75% of total volume of spillage in the North Slope region over a seven-year period came from transportation infrastructure. Follow-up reports in 2007, "10-year Statewide Summary of Oil and Hazardous Spill Data, Fiscal Years 1996-2005" and "Summary of Oil and Hazardous Substance Spills by Subarea (July 1, 1995-June 30, 2005),confirmed this trend.

Figure 1-1 shows the major crude oil and gas production infrastructure on the North Slope.

Table 1-1 lists the current oil fields[2] and the year they came online, with trends in produced water/produced oil ratios, information about peak production levels, and a summary of the miles of flowlines and oil transmission pipelines associated with the oil field infrastructure.

Table 1-1. Summary of production statistics and miles of flowlines and oil transmission pipelines for North Slope oil fields.

Oil Field	First Month Production	Last Month Production	Changes in Produced Water/Oil Ratios over time[2]	Peak production (date & level in bbl)	Total Miles of Flowlines	Total Miles of OTP	Total Combined Pipeline Miles
Badami	Aug 1998	Aug 2007	No produced water	Sept 1998; 223,455 bbl	0	25	25
Colville River, Alpine	Nov 2000	-	Produced oil was always greater than produced water.	May 2007; 4,305,471 bbl	26	34	60
Endicott	July 1986	-	Produced water surpassed produced oil in Dec 1994; oil surpassed water in Feb 1995; produced water has been greater than produced oil since April 1995.	Oct 1992; 3,703,032 bbl	8	26	34
Kuparuk River	Dec 1981	-	Produced water had a greater volume than oil starting in April 1992; volumes switched back and forth several times until December 1993; produced water has been greater than produced oil since December 1993.	Dec 1992; 10,520,965 bbl	303	37	340
Milne Point	May 1985	-	From May 1985 through July 1985, only water was produced, production ceased July 1985 & resumed November 1985, with oil exceeding water. Ratio has fluctuated over time. As of January 1997, produced water has exceeded produced oil.	July 1998; 1,825,669 bbl	35	11	46
Northstar	Oct 2001	-	Produced oil has always exceeded produced water.	Jan 2004; 2,439,547 bbl	0	17	17
Prudhoe Bay	Jan 1977	-	In Sept 1992, produced water surpassed produced oil.	Jan 1987; 51,847,411 bbl	438	29	467
Total Miles					**810**	**179**	**989**

2 Oil fields are defined by the Alaska Oil and Gas Conservation Commission for the purpose of production reporting. The Ooguruk oil field was not included in this study, because there were no loss-of-integrity spills reported from this new oil field during the study period.

3 All producing fields started with higher proportionate volume of oil than water, with the exception of Milne Point.

1.3.2 North Slope Crude Oil Production Infrastructure

As shown in Figure 1-2, oil production on the North Slope begins at the well, located on well pads (Figure 1-3) that are typically constructed of gravel and may be located onshore or offshore on islands. Each well produces oil, gas, and water in varying proportions. Flowlines carry this three-phase mixture from the drill site to the processing center. The processing center (Figure 1-4) contains a variety of equipment, including three-phase separators and gas conditioning equipment. Oil is filtered to remove any sediment and is then routed through a crude oil transmission pipeline for delivery to Pump Station 1 of the Trans-Alaska Pipeline (TAPS), as shown in Figure 1-5. Natural gas is processed to remove liquids, then compressed and reinjected into the reservoir or used as a fuel supply for production operations. Produced water is chemically treated and also injected into the reservoir. The reinjected gas and water help to maintain reservoir pressure.

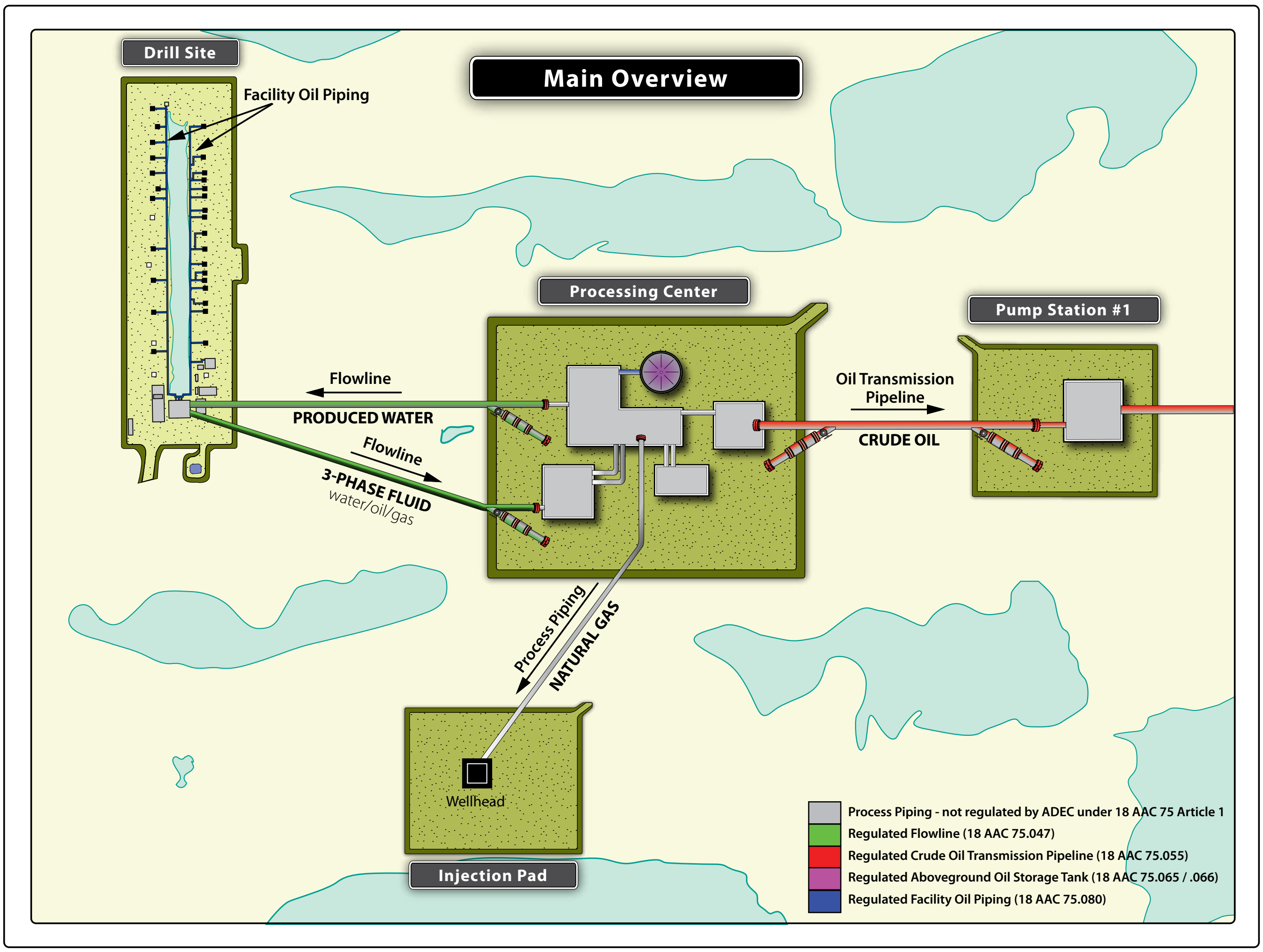

Figure 1-2. Overview of typical North Slope crude oil infrastructure components.

Pipelines that carry water, gas,[4] and crude oil vary in diameter and are typically installed above ground on vertical support members. Depending upon the type of pipeline and the materials it transports, it

4 In-field gas pipelines are not regulated the State of Alaska.

is subject to different state regulations. The following regulatory categories and definitions in state regulations provided the basis for categorizing North Slope spills for consideration in this analysis:

- Well – Regulated by Alaska Oil and Gas Conservation Commission - 20 AAC 25
- Facility Oil Piping - 18 AAC 75.080, 75.990(171)
- Flowline – 18 AAC 75.047, 75.990(173)
- Oil Transmission Pipeline – 18 AAC 75.055, 75.990(134)
- Above Ground Oil Storage Tank – 18 AAC 75.065, 75.990(165)
- Process Piping – not regulated by Alaska State agencies.

Of the four pipeline regulatory categories shown in Figure 1-2, two were given special focus during this analysis: flowlines[5] and crude oil transmission pipelines.[6]

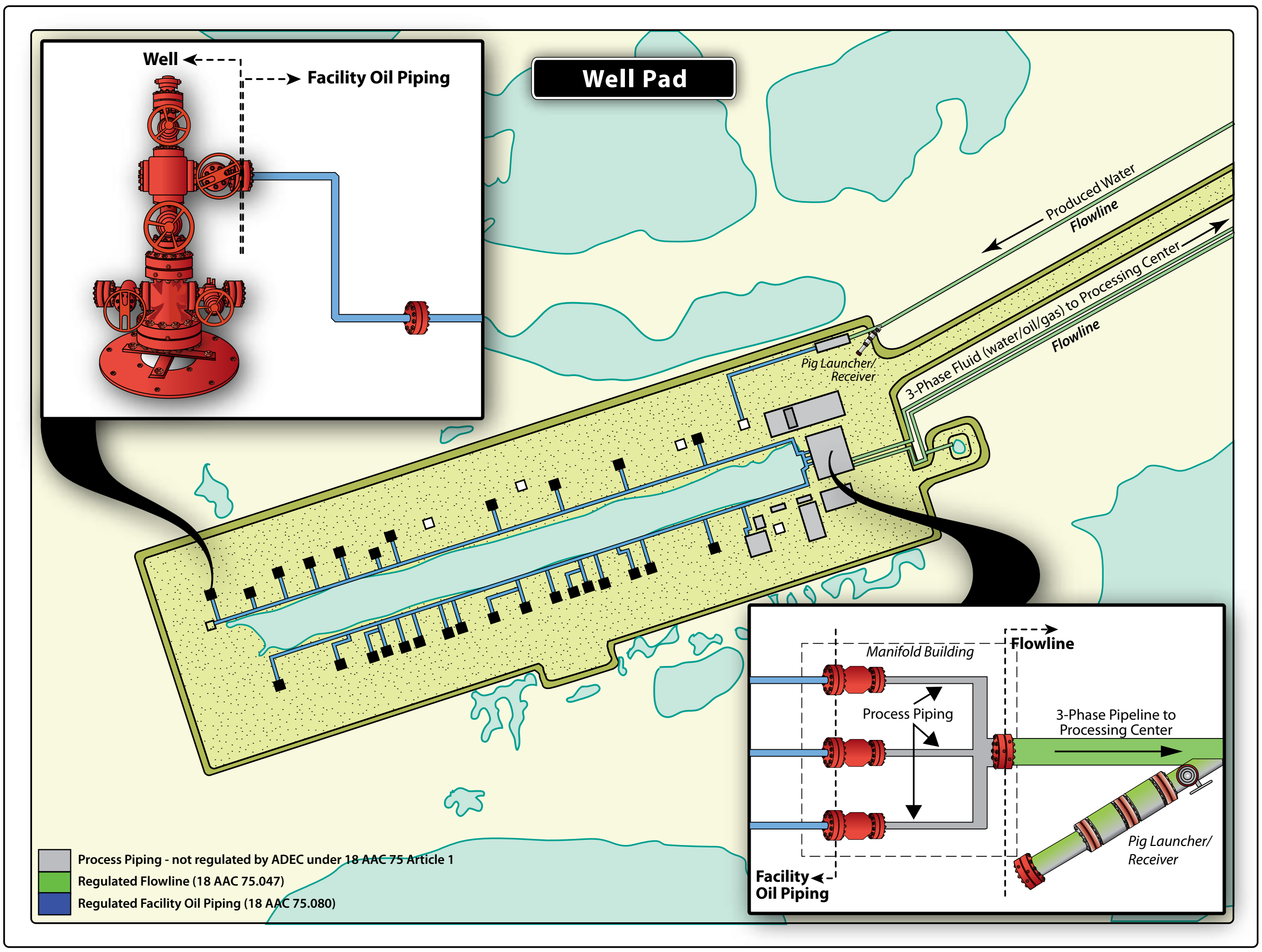

Figure 1-3. Typical well pad.

5 As defined and regulated by 18 AAC 75.047
6 As defined and regulated by 18 AAC 75.055

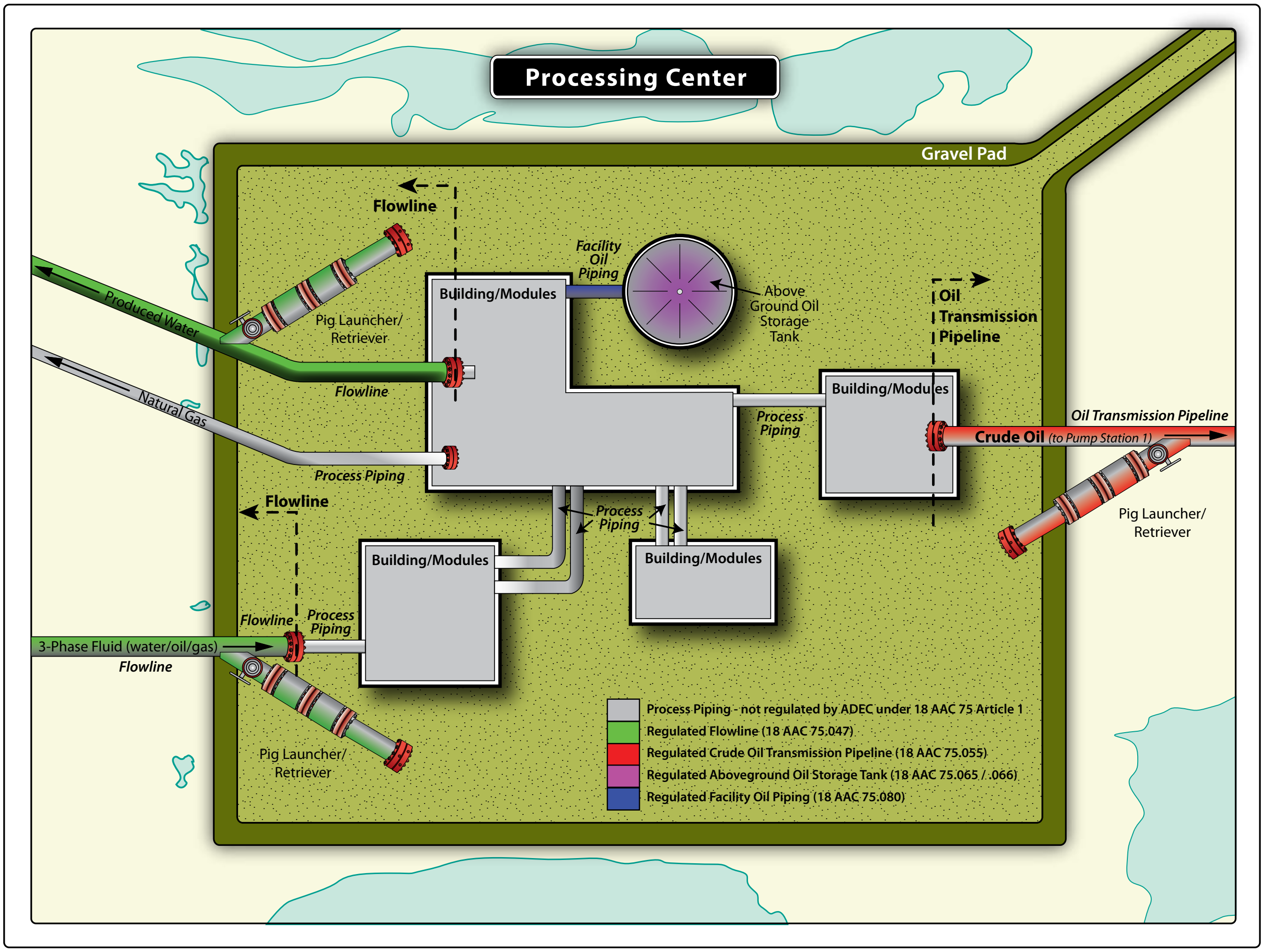

Figure 1-4. Typical crude oil processing center.

1.4 Project Scope

1.4.1 Project Approach

The North Slope Spills Analysis considers the leaks due to loss-of-integrity from crude oil production on Alaska's North Slope. For the purposes of this analysis, *loss-of-integrity leaks* were defined as a failure that leads to a reportable spill of any fluids in the production stream, including mechanical failures and human errors. This analysis considers the frequency, severity, and causes of North Slope oil spills by regulatory category, and provides recommendations to the State of Alaska to reduce the frequency and severity of future spills. An Expert Panel was convened to review the analysis and provide recommendations about potential risk reduction measures that address the relationship between causal factors and infrastructure characteristics.

1.4.2 Geographic and Process Flow Scope

The geographic scope of this analysis was contained within the North Slope Region[7] and was limited to oil production infrastructure, which includes wells and associated piping, flowlines, process centers with their associated piping and above ground storage tanks, and crude oil transmission lines. Pump

7 As defined in 18 AAC 75.495(a)(9)

Station 1 of the Trans-Alaska Pipeline System (TAPS) and the associated pipeline infrastructure south to Valdez was specifically excluded from this analysis. Figure 1-1 shows the geographic scope of the analysis. Figure 1-2 shows the process flow scope of the analysis.

1.4.3 Scope and Limitations of Analysis

The analysis utilized available data from spills reported to the ADEC from North Slope oil production operators during the period of July 1, 1995 to December 31, 2009. As discussed in Section 2.2, spill data and supplementary information on cause, location, and infrastructure component was collected through ADEC files and other publicly available information. North Slope operators provided review of flowline and oil transmission pipeline spill records. The analysis was limited by quality and quantity of data availability. The depth and limitations of the data set used in this analysis are discussed further in Section 2.5.

Since the geographic and infrastructure scope was limited to loss-of-integrity spills from oil production upstream from TAPS Pump Station 1 on the North Slope, the observations and analysis may not apply to other infrastructure components or other geographic regions. Also, the scope of the analysis essentially limited the data set to spills from two operators. While the applicability of this analysis is limited to a small subset of Alaska's extensive oil and gas production infrastructure, the methods applied in this analysis may provide a model for future studies to look at other segments of this infrastructure, or to make comparisons across infrastructure components or locations.

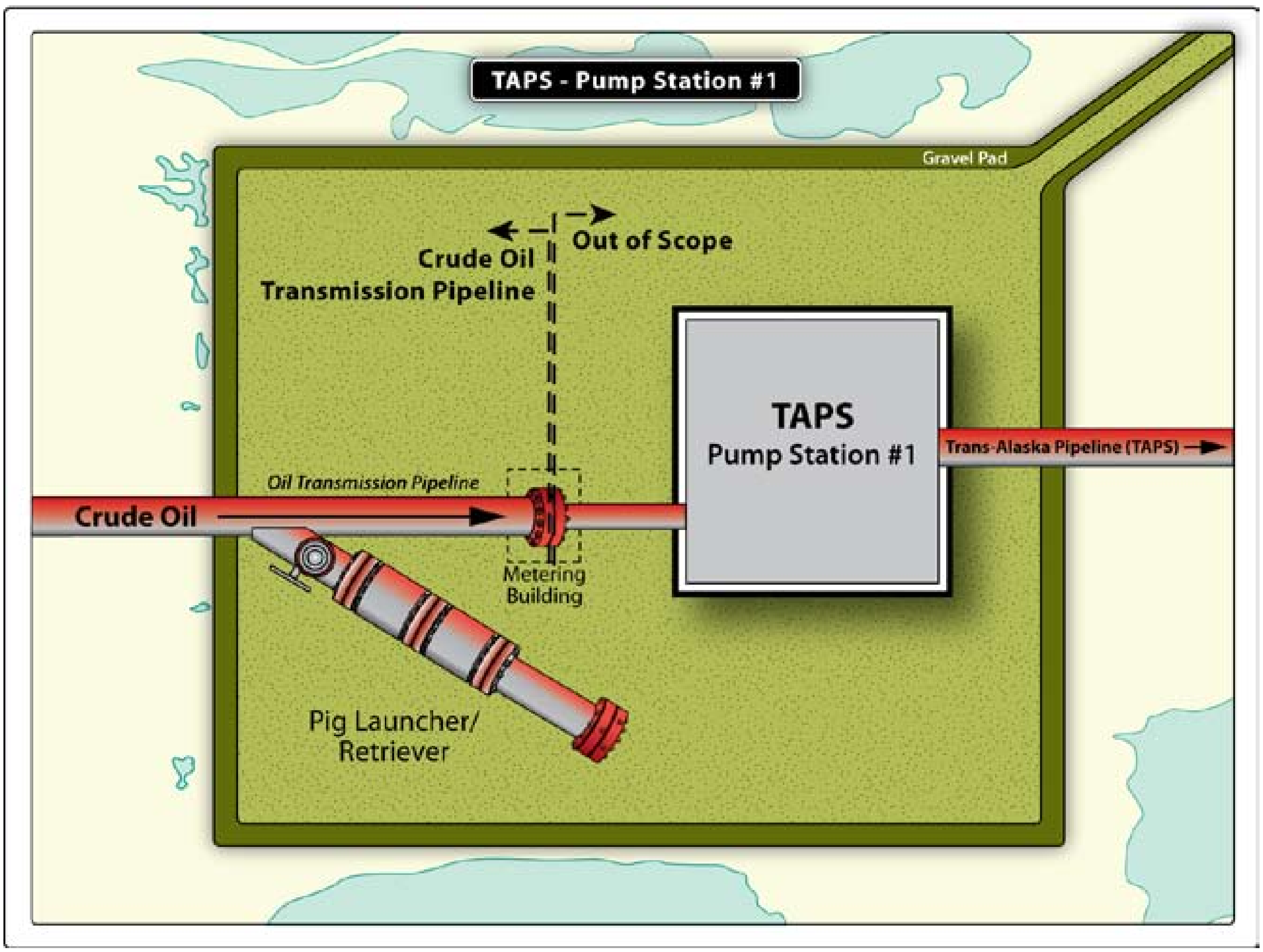

Figure 1-5. Crude oil transmission pipeline intersection with TAPS Pump Station 1.

There are many ways to assess and measure risks. The initial methodology proposed to conduct the Alaska Risk Assessment would have considered potential failure rates for various components of Alaska's oil and gas infrastructure and then evaluated the potential consequences from those failures to make some comparisons among risks (DoyonEmerald and ABS, 2009). That approach would have aggregated data from multiple sources to model potential failure rates. In contrast, the methodology applied in the North Slope Spills Analysis looks at actual failure rates based on past loss-of-integrity spills and attempts to draw conclusions about system-wide risks based on trends in past spill occurrences. There are benefits and drawbacks to both approaches. Unlike a traditional risk assessment, which measures risk as a product of both probability and consequence, the North Slope Spills Analysis focuses only on probability. In the North Slope Spills Analysis, probability is calculated based on past occurrences and not on models of potential future events. A strength of this type of approach is that it reflects actual data from the Alaska North Slope infrastructure, rather than surrogate data aggregated from other sources. A drawback is that this type of analysis is strictly backward-looking. There may be other potential causes or sources of loss-of-integrity that have not occurred in the past but could threaten the system in the future. The North Slope Spills Analysis will not provide any insight into the types of failures that could occur but have not yet occurred within the system.

Future studies could build on the North Slope Spills Analysis by conducting a consequence analysis for the spill trends identified in this report.

METHODS 2

2.1 Analysis Design

The key question underlying this analysis was:

> *Are there identifiable trends in loss-of-integrity spills from crude oil piping infrastructure on the North Slope that could be used to identify mitigation measures that would prevent future spills?*

The State was particularly interested in trends over time, causal factors, spill impacts, spill detection methods or timing, and infrastructure characteristics (regulatory category and process flow). To compile a database having sufficient information to provide insight into these questions, the analysis team compiled data from several sources. These sources are discussed in Section 2.2. Appendix D contains a copy of the final spill data set of 640 spills, which were the basis of the analysis.

The information collected was compiled and analyzed for those spills resulting from loss-of-integrity. The analysis of data (Section 3) was presented to an Expert Panel for their review, and based on the analysis, the Panel provided recommendations (Section 5) to agencies and operators on mitigation measures to reduce future spills.

2.2 Data Sources and Collection Procedures

Documents and databases primarily available through public records were used to correct data on spills, oil production, and pipelines. Spill records from the ADEC SPILLS database, records associated with North Slope oil field spills, the operator's approved Oil Discharge Prevention and Contingency Plans (C-Plans),[1] North Slope Charter Agreement Corrosion Reports, pipeline parameter information provided by the operators to ADEC, and on-line production statistics maintained by the Alaska Oil & Gas Conservation Commission (AOGCC) were primary sources used to support this analysis.

Data of interest to this analysis, yet not readily available through public sources included: leak detection method/time; pipeline parameter data; investigation type; contributing (root) cause analysis; spill location; and diagrams. This information was compiled, where available, from ADEC spill case records and queries to North Slope operators.

2.2.1 Alaska Spill Reporting Requirements

The State of Alaska requires that all spills of oil or hydrocarbons to water of any size and spills to land in excess of 55 gallons must be reported to ADEC as soon as they are detected.[2] Oil spills to land in excess of 10 gallons and spills to secondary containment in excess of 55 gallons must be reported

1 As required by 18 AAC 75.425, 18 AAC 75.445, and 18 AAC 75.455.

2 Hazardous materials spills of any size to any receiving area must also be reported as soon as they are detected.

within 48 hours of detection.[3] These requirements set the basis for collecting information that can be converted to data on oil and hazardous substance spills.

The ADEC reporting requirements for oil spills include both an initial and a final report. Initial reports provide information on the party reporting the spill, the date/time, the location source and preliminary cause, product type and amount spilled, area impacted, cleanup and disposal methods, and other relevant information or comments. In addition to the initial spill reporting information collected by ADEC at intake, the Responsible Party (spiller) must submit a final incident report[4] within 15 days after the cleanup is completed, or if no cleanup occurs, within 15 days after the discharge. The final report must contain the following information:

- Date/time of the discharge or release;
- Location of the discharge or release;
- Name of the facility or operation;
- Name, mailing address, and telephone number of each responsible person, and the owner and the operator of the facility or operations;
- Type and amount of each hazardous substance discharged or released;
- Factors that caused or contributed to the discharge or release;
- A description of any environmental effects of the discharge or release, or the containment and cleanup, to the extent those effects can be identified;
- A description of the containment and cleanup action taken;
- The estimated amount of hazardous substance cleaned up, and hazardous waste generated;
- The date and method of disposal or treatment of the hazardous substance, contaminated equipment, materials soil and water;
- A description of actions being taken to prevent another discharge or release; and,
- Other information that the department requires to fully assess the cause and impact of the discharge or release, including any sampling reports and a description and estimate of any remaining contamination.

2.2.2 ADEC SPILLS Database

The information collected through both initial and final reports on all spills meeting the reporting thresholds is compiled in the SPILLS database, which is managed by ADEC. This database was the source of the initial data set used in this analysis.

The ADEC SPILLS database was originally launched July 1, 1995 with the goal of electronically managing information about oil and hazardous substance releases on a statewide basis. Oil and hazardous substance spill reports/notifications are received by the ADEC Area Response Teams from the responsible party or complainant by telephone or facsimile (ADEC 2003). The report is then entered into the database by ADEC staff. Spill records are loaded into a web application for browsing and editing by individual spill upon user request.[5]

3 The general requirements for reporting spills to the ADEC are found in Alaska Statute (AS 46.03.755, AS 46.03.745 and AS 46.09.010) and regulations (18 AAC 75.300).

4 18 AAC 75.300(e)

5 The SPILLS database can be queried online through the following link: http://www.dec.state.ak.us/spar/perp/search/search.asp

Data from the SPILLS database is used by ADEC for program management, budgeting and performance measures, spill planning and prevention, responding to public information requests, gauging the effectiveness of regulatory programs, and identifying the need for new or strengthened prevention measures.

2.2.3 Alaska Oil Discharge Prevention and Contingency Plans

The ADEC Industry Preparedness Program maintains an Oil Discharge Prevention and Contingency Plan (C-Plan) database, which is linked to the ADEC SPILLS database, so that spill data can be analyzed for facilities regulated by the State of Alaska (ADEC 2007).

Within the C-Plans themselves, operators report additional information about discharge history and prevention programs. The owner or operator of a facility is required to maintain, for the life of the facility or operation, a history of known oil discharges over 55-gallons[6] within the state. Information includes the source, cause, amount, and corrective action taken. Although this information is not captured in the SPILLS database, the Operator's C-plans themselves were reviewed for spills considered in this analysis. Table 2-1 lists these C-Plans, which were used to gather and validate relevant data associated with in-scope oil spills for each facility.

Table 2-1. List of Alaska C-Plans reviewed for this analysis.

C-Plan holder	Plan Title	Expiration Date
BP	Greater Prudhoe Bay Production	June 27, 2012
BP	Northstar Production	June 28, 2012
BP	Endicott-Badami Production	May 22, 2012
BP	Milne Point Production	April 20, 2012
CP	Alpine Production	April 29, 2013
CP	Kuparuk Production	May 2, 2013

In addition to the oil spill information, each C-Plan contains facility diagrams which were used to identify where a spill occurred within the production unit and to assign the case to its proper regulatory category. The facility diagrams were also used for developing a geospatial depiction of spill locations.

2.2.4 Industry Corrosion Reports

The Charter for Development of the Alaskan North Slope (Charter), signed on December 2, 1999, is an agreement between the State of Alaska, BP Exploration (Alaska) Inc., and ARCO, which led the State of Alaska to support a merger between BP and ARCO. The Charter is the first antitrust agreement in the U.S. to include environmental provisions. The ADEC is charged with managing and overseeing the environmental provisions described under sections II.A and II.B of the Charter agreement (ADEC 2010a http://www.dec.state.ak.us/spar/ipp/docs/Charter%20Agreement.pdf, April 2010). The key environmental provision that provided information for this analysis was associated with state oversight of industry's pipeline corrosion monitoring and structural integrity program on the North Slope. Specifically, Section II.A.6 of the Charter Agreement states:

> *BP and ARCO will, in consultation with ADEC, develop a performance management program for the regular review of BP and ARCO's corrosion monitoring and related practices for non-common carrier*

6 18 AAC 75.020(d)

> *North Slope pipelines operated by BP or ARCO. This program will include meet and confer work sessions between BP, ARCO and ADEC, scheduled on average twice per year, reports by BP and ARCO of their current and projected monitoring, maintenance and inspection practices to assess and to remedy potential or actual corrosion and other structural concerns related to these lines, and ongoing consultation with ADEC regarding environmental control technologies and management practices.*

For the past ten years, the North Slope operators have submitted Corrosion Reports to ADEC. All of these reports have been posted on the Internet for public access and were used during this analysis to validate data obtained from the ADEC spill case files and C-Plans.

2.2.5 Production Statistics

The AOGCC maintains monthly production reports for each active oil field in Alaska. These reports are available online and they include data on the amount of: crude oil, produced water, and natural gas production summarized by oil field and production pool. Archived data is also available upon request to AOGCC. Production data was collected from AOGCC for the study period of July 1, 1995 to December 31, 2009. The data was used in an attempt to look for trends regarding the change over time in production pool fluids and frequency/cause of oil and produced water spills. This data is presented in Appendix G.

2.2.6 Supplemental Data from Record Review and Operator Input

Compilation of publicly available data still left many missing data, particularly with respect to leak detection, pipeline parameters, investigation type, contributing cause, spill location and diagrams. Because this information was considered to be critical to the analysis, the research team conducted supplemental data collection from two main sources: review of ADEC spill case files, and operator validation and input. ADEC maintains hard copy case files for all closed spill investigations, and a team was dispatched to Fairbanks to review these case files and collect data for this analysis. The two operators involved in the analysis – BP and CP also provided assistance with data review and verification by reviewing individual spill records and providing supplemental information where possible in the timeframe of the research phase of the analysis.

Since information on leak detection was scarce in the publicly available data sources, operators were asked to provide any information they had about how spills were detected and the timeframe for detection of scope, flowline and oil transmission pipeline spills.[7] Data to explain how a leak was detected (visual, odor, vapor monitoring equipment, leak detection system) and how long the spill was leaking prior to discovery is not routinely captured or collected in the ADEC SPILLS database or case files.

Pipeline parameter data, including the type, age, location, characteristics (coating, insulation), in-line inspection (smart pigging) frequency and history, were also of interest to this analysis. Understanding the age of pipeline at failure, location of pipeline (above grade, below grade) and type of failure was key for developing effective mitigation measures. Some pipeline parameter data provided by operators was obtained from ADEC, specifically data submitted under the state requirements governing flowlines at production facilities.[8] Additional information was collected by reviewing ADEC case files, corrosion reports and C-Plans. The operators were also asked to provide the pipeline parameter information for in-scope flowline and oil transmission pipelines, as part of the data collection effort.

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7 Note that state regulations requiring leak detection technologies apply only to crude oil transmission pipelines, per 18 AAC 75.055.
8 18 AAC 75.047.

Although the ADEC SPILLS database includes a required data entry for spill location, this business rule didn't go into effect until 2006.[9] Spill location data for spills pre-dating this requirement was weak; yet, identifying the geographic location of spills was an important component of this analysis. Spill location data was collected by reviewing case files and through inquiries to the operators to determine whether a pipe and instrument diagram and process flow diagram existed for the pipeline involved. When possible, the operators provided additional data or validated the location during their review period.

Spill investigation information was also gathered primarily from operators. Spill investigations are not conducted by the agencies for all events, and the decision to conduct an investigation is typically driven by the magnitude of an incident and its environmental impact. To develop more information about when investigations have historically been conducted, operators were asked whether an investigation was conducted for each spill, the type of investigation (internal, joint with agency, agency or 3rd party), and the primary and contributing causes of failure. Some information on spill investigations was also collected from the ADEC case files, C-Plan spill history, or the corrosion reports. Operators were also asked to validate this information.

Spills that occurred before 1995 were not captured in the SPILLS database. Information on spills from 1971 through 1995 was compiled through historical spill records housed in the ADEC Fairbanks Office. Data from spills that predate 1995 were not included in the analysis in Section 4.

2.3 Compilation and Sorting of Data for Analysis

2.3.1 North Slope Spills Database Design and Management

The initial data set utilized for this study was an export from the ADEC SPILLS database with spill case information for 6,059 spill cases from the North Slope oil fields. This initial data set included all spills between July 1995 and December 2009, all spill substance types and all sources. Additionally, the ADEC Northern Regional Office provided another data set, with data for spills occurring between 1971 and 1995. This data set included over 10,000 spill cases of all substance types and sources that occurred prior to the establishment of the SPILLS database.

In order to effectively manage the effort of compiling, validating and manipulating the spill data, a data management system was created to facilitate easy, on-screen review, editing and initial analysis. A Microsoft Access 2007 database, referred to in this analysis as the North Slope Spills (NSS) database, was developed as the central repository for all spill case data. Compiling and formatting the data in this manner enabled rapid query and report generation, expanded search and editing capability, and facilitated quality control review and revision capacity that was critical to support accurate data entry, tracking, transmission and sharing.

To retain the integrity of the initial data provided from the ADEC SPILLS database, additional fields were built into the NSS database to enable expansion of information associated with each case file as the result of review, analysis, research, and operator review. The original ADEC data fields were not modified, but they were supplemented as additional information was compiled. Appendix B contains screen shots of data entry fields from the NSS database.

2.3.2 Spill Case Review and Assessment

A team of subject matter experts was assembled to review the initial data set and structure in order to

9 Personal communication with ADEC-PERP Spill Database Manager, June 9, 2010.

assess the quality of information available for each case. The 6,059 cases from the SPILLS database export were then sorted and only cases that involved the release of crude oil and/or produced water (e.g. process water, seawater, etc.) were kept.[10] This reduced the total spill population to 1,153 cases.

Because the SPILLS database could not be used to determine if the spill was a result of loss-of-integrity, a systematic review of the 1,153 spill case files was undertaken to narrow the data. Sections 2.3.3 through 2.3.5 describe the 3-step process used to make these determinations.

2.3.3 Initial Review for Loss-of-Integrity and Regulatory Categorization

The first step in narrowing the spill case files for further analysis was an initial determination as to whether the case was considered a loss-of-integrity spill. Cases were considered out of scope if they met any of the following conditions:

- The spill case did not come from the oil production train; or
- The pipeline was out of service at the time of the spill; or
- The spill originated from something other than the oil production infrastructure (such as drilling or workover operations, vehicles, portable tanks, etc).

The second step was to assign the case to a regulatory category. The regulatory categories and subcategories used are described in Table 2-2. Subcategories are not based in regulation but were derived based on the service of the facility/pipeline where the spill occurred. Figures 1-2 through 1-5 show how these categories apply to various infrastructure components.

Table 2-2. Pipeline regulatory categories and subcategories[11].

Regulatory Category	Subcategory	Regulation
Wells	No subcategory	AOGCC – 20 AAC 25
Facility Oil Piping	Well pad/drill site Processing Center, module to oil storage tank	18 AAC 75.080, 18 AAC 75.990(171)
Flow Line	Cross-Country 3-Phase pipeline Produced Water pipeline Operational activities, such as pigging	18 AAC 75.047, 18 AAC 75.990(173)
Oil Transmission Pipeline	Cross-country crude oil pipeline Operational activities, such as pigging	18 AAC 75.055, 18 AAC 75.990(134)
Above Ground Oil Storage Tank	No subcategory	18 AAC 75.065, 75.990(165)
Process Piping Not regulated by State	Manifold building (interconnection) Processing center (interconnection) Seawater pipeline Natural gas pipeline	N/A

Additionally during this initial review, information on environmental impact, corrective actions, and general comments and notes were added to each spill case as appropriate, based on the spill discharge histories reported in the C-Plans. Similarly, the North Slope Charter Agreement Corrosion Reports

10 The only products of the North Slope oil production are crude oil, produced water, and natural gas. Any other substance spilled would not have resulted from the loss-of-integrity of the system.

11 Regulatory Categories as defined by the Alaska Administrative Code (AAC) and the Alaska Oil and Gas Conservation Commission (AOGCC) regulations, and through collaboration with Alaska Department of Environmental Conservation (ADEC) staff subject matter experts.

(2000 to 2009) from BP, ConocoPhillips (CP), and Coffman (ADEC 2010b, http://www.dec.state.ak.us/spar/ipp/corrosion/index.htm, April 2010) were reviewed and applicable spill case information was added to the database. This effort also resulted in the identification of additional spill cases that were noted in the corrosion reports but were not initially identified from review of the ADEC SPILLS database and spill case information.

2.3.4 Spill Case Research Team Review

The analysis design focused on flowlines and oil transmission pipelines because each of these categories have had some major spills in the past years and these cross-country pipelines present the largest threat to sensitive habitat. The outcome was a flowline and oil transmission pipeline case population that totaled 103 spill cases. A spill case research team examined all available documentation for the flowline and oil transmission pipeline spill cases to extract as much information as possible about immediate and contributing causes. Reference materials utilized for causal investigation review were: spill summary reports generated from the NSS database; ADEC Situation Reports; Incident Investigation Reports, Operator C-Plans; oil field histories; BP and CP corrosion reports from 2000 to 2009; Coffman corrosion reports from 2000 to 2004; and physical case files.

The causal investigation reviewers utilized the resources listed above to:

- Validate regulatory categorization and correlating sub-categorization;
- Determine the immediate and contributing causal factors;
- Assess the extent of environmental impact;
- Review the types of corrective actions discussed and implemented; and
- Capture any available pipeline design and operating parameters (e.g. nominal wall thickness, outside diameter, installation date, throughput, maximum allowable operating pressure, etc.).

The availability and quality of data noted during this case-by-case review varied greatly based on the level of detail captured in each case file and the amount of information contained in the corresponding resources reviewed.

2.3.5 Operator Validation

The third and final step in the spill case review process included the engagement of the North Slope pipeline operators, BP and CP, to validate the information compiled for cases from each facility. Operator validation solidified the regulatory category assignments, refined the scope of cases included in the flowline and oil transmission pipeline case population, and expanded upon the data available for most cases.[12] The level of detail and ultimately the availability of additional investigative information varied significantly between spill cases and between operators. Some sizable information gaps in pipeline design and operating parameters remain.

At the conclusion of operator review, the total case population that was established for further analysis and presentation to the Expert Panel for review totaled 80 spill cases, which include 71 flowline cases, and 9 oil transmission pipeline (OTP) cases. Figure 2-1 shows how the spill cases were narrowed down through the various levels of review and investigation.

12 Operator Review and Validation of the Flow Line and Oil Transmission Pipeline spill cases totaled 75 of 80 cases (94%).

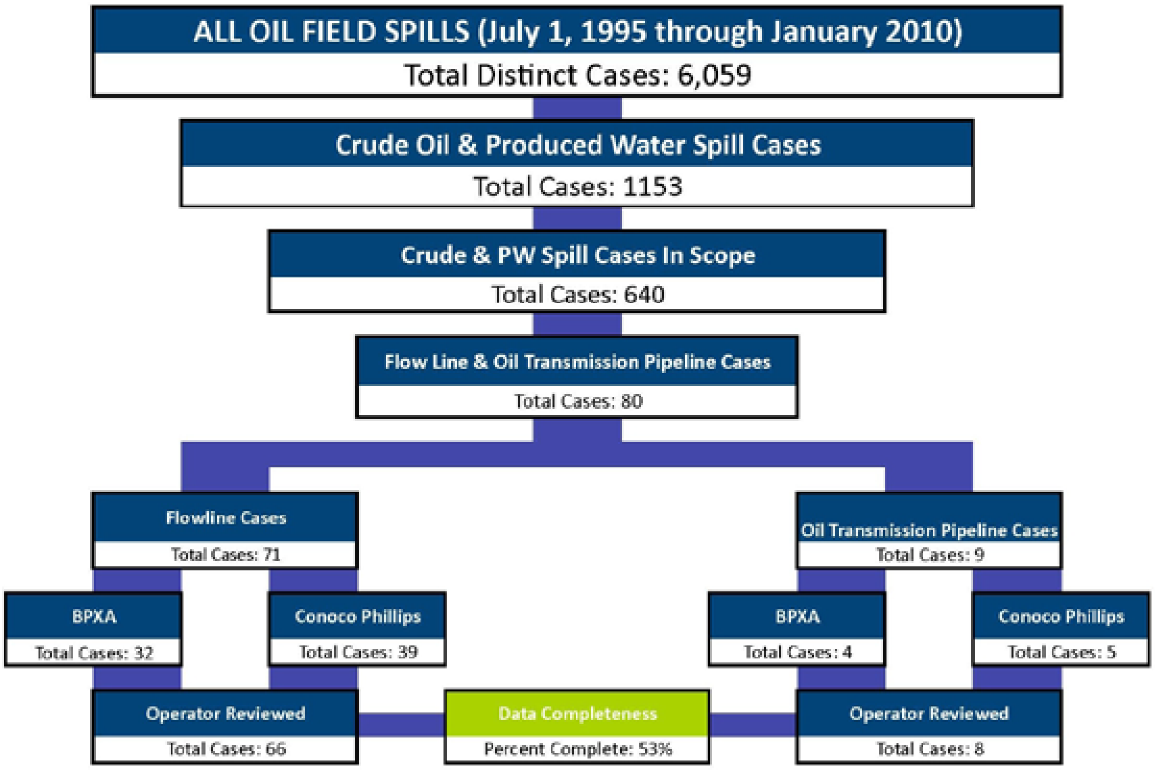


Figure 2-1. North Slope spill data set reduction.

2.4 Geospatial Referencing

To facilitate mapping and geospatial analysis of the North Slope Spills data, a geospatial database was developed for the infrastructure catalogue (See Appendix C) and the final subset of 640 spills were geo-tagged. The goal of geospatially referencing this information was to:

- Identify and map the North Slope crude oil pipeline infrastructure by creating a data set that could be displayed and manipulated in either a Google Earth or Arc GIS application;
- Associate, to the extent possible, every spill with a specific geospatial location; and
- Provide a geospatial tag for every specific pipeline route.

The specific parameters sought for the geospatial data included oil field, regulatory category, service, starting point, ending point, pipeline length, nominal wall thickness, outside diameter, yield strength, grade, installation date, throughput, and maximum allowable operating pressure.

The geospatial data were used to tag spills to facilities and pipelines. Google Earth was used to display this data, which can be viewed by regulatory category and sub-category, facility type, and spill number. The user can evaluate the specifics of any spill by clicking on the icon representing it.

2.5 Data Quality

2.5.1 Quality Assurance and Control

Given the size and complexity of the data set and data-gathering process, substantial quality assurance/quality control (QA/QC) procedures were established to protect the integrity of the data and the database. Table 2-3 summarizes the QA/QC process as it was applied to the data compilation and sorting process described in Section 2.3.

Table 2-3. Quality assurance/quality control procedures.

QA/QC Procedure	Result
Database Manager Oversight	A single database manager was assigned to oversee all interactions with the database. The North Slope Spills database manager provided daily oversight and accuracy of data entry evaluation for all information entered into the database.
Data Entry Oversight	When it was required that multiple people work in the database, a schedule (4 hour time blocks) was created among team members to input case file information into the database. At the conclusion of each time period, the respective team member would upload the latest version of the database to an FTP site and notify the next user of the updated database availability. This process ensured that all data entry persons were working in the most current database. The Database Manager oversaw compliance with this policy.
Regulatory Category and In Scope/Out of Scope Assessment	In an effort to validate the initial regulatory category assignments and determinations of loss-of-integrity, a random sampling of cases was taken to assess the accuracy of these assignments. This approach proved very effective in recognizing, early in the project, a high error rate in initial categorization that enabled the data collection team to adapt and adjust their approach to include additional cases for location and review.
Data Collection Forms (DCFs)	DCFs[13] and Spill Summary Reports were provided to the Causal Research Team members as a starting point for their investigative efforts. DCFs served to standardize the information collection and organization process, and facilitated entry into the NSS database.
DCF Entry	The Database Manager was the sole point of entry for all DCFs into the North Slope Spills database.
Operator Validation	The Industry / Operator Validation actually served as an inherent means of QA/QC as both BP and CP reviewed the accuracy of data in each DCF.
Final Causal Investigative Team Review	Upon receipt of the operator validated DCFs, the appropriate causal research team member would again review the data for clarity, agreement with regulatory categorization, and completeness.
Review of all in scope cases	All in scope cases were reviewed by at least two reviewers, multiple times through the data entry and data addition/revision process.

2.5.2 Data Completeness

The ADEC SPILLS database is used to manage statewide oil and hazardous substance spill information, analyze data to identify spill trends and provide ADEC staff with information relevant to their caseload management. As with any database, the accuracy and completeness of reported information resides with the initial and follow-on data entry by ADEC staff. Business rules have been implemented to ensure core data is entered into the database, but it became apparent during the review process that spill case records were often times inaccurate and/or incomplete.

Since the SPILLS database was designed to accommodate all reported discharges, broad categories for facility category, types and sub-types were established. The sub-types for onshore and offshore oil production were limited to flowlines, crude oil transmission pipelines and field processing. The current sub-types and definitions do not directly match the regulatory definitions and as a result multiple reviews of the case files were required to determine whether a spill case was in scope or out of scope, and which regulatory category should be assigned to the case. Due to the lack of information in some case files, best professional judgment of the reviewers was used to make these determinations.

13 See example in Appendix B.

This same approach exists for cause type, although 32 cause identifications have been created in the SPILLS database. The SPILLS database identifies immediate (proximate) cause only and does not include any means for collecting and categorizing information related to contributing causes. Contributing causes are those factors that contributed or led to the immediate cause and are sometimes referred to as "root cause."

North Slope spill case files are retained at the ADEC Fairbanks office. The case files are well organized, allowing for easy retrieval and review of information. Relevant documents were scanned to establish electronic case file review. While reviewing case files, it became apparent that many of the cases were closed out by ADEC staff before all of the basic information had been compiled, and in many cases final report forms required under 18 AAC 75.300(e) were not included in the case file. Attempts were made by the analysis team to collect basic data from other documents listed in Section 2.2 of this report to fill the data gap. For those cases where additional data could not be found, best professional judgment was used by the researcher to determine whether the case was in-scope or out-of-scope for this analysis.

Figure 2-2 represents a Completeness Matrix[14] used to track missing data for each flowline and oil transmission pipeline case. Information that is not routinely collected by ADEC during the time of a spill and entered into the SPILLS database or captured as case documentation includes: leak detection method and time to discovery; spill location-pipe and instrument diagrams, process flow diagrams; pipeline pigging history and contributing causes associated with the incident. On average, after all the relevant spill case sources noted previously were reviewed, and appropriate information entered into the NSS database, data completeness reached 53%.

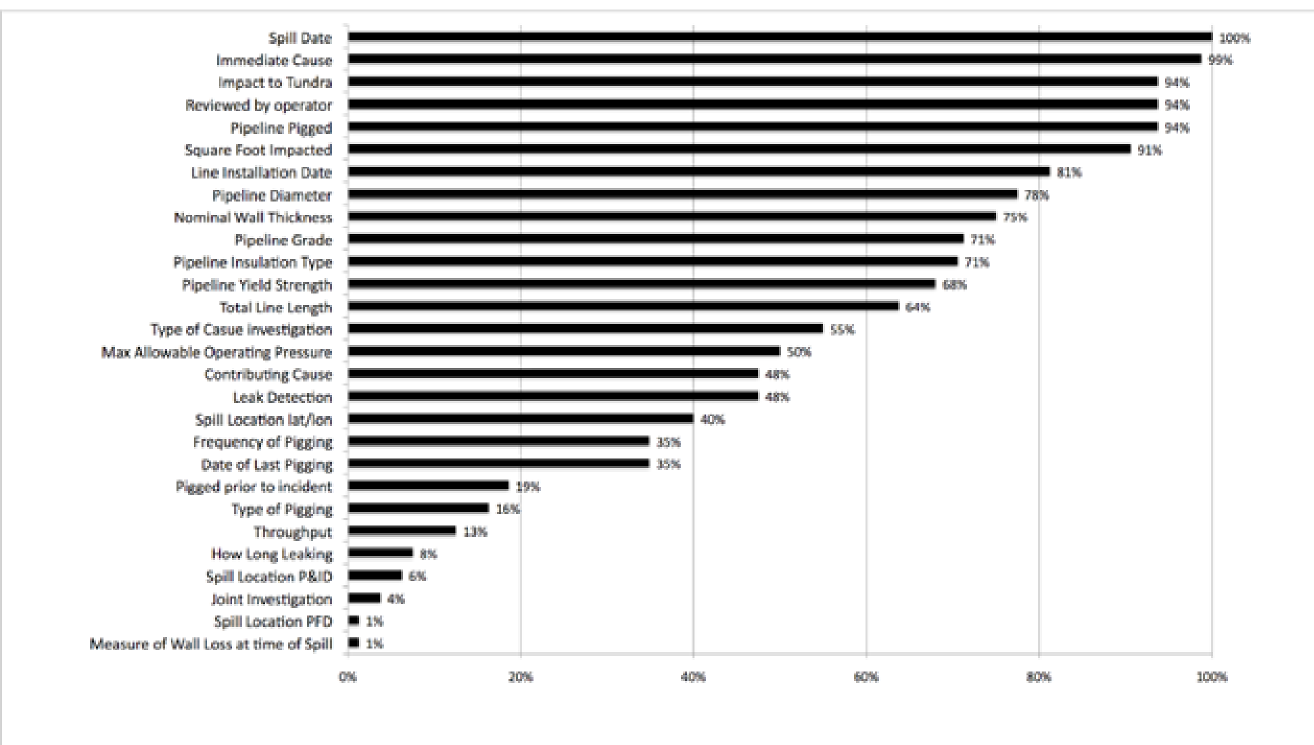


Figure 2-2. Data completeness prior to analysis.

14 The principal pipeline design and operating parameter data was largely complete (~83% complete on average through the pipeline length data column) on June 4, 2010.

2.6 Expert Panel

An Expert Panel was convened to provide independent review and analysis of the North Slope spills. Panel members were selected based on their demonstrated knowledge in one or more of the following areas:

- General knowledge of crude oil production operations and measures used to inspect for aging conditions, detect leaks, and prevent leaks and spills;
- Knowledge of loss-of-integrity root cause investigations and common cause analysis; and
- Knowledge of analysis of leak data and general engineering practices

The charge of the Expert Panel was to provide recommendations on measures, programs, and practices to monitor and address common causes of failures identified in the analysis of spill data. The Expert Panel operated under a charter and met four times during the life of the project. The Expert Panel developed the recommendations presented in Section 4 of this report.

Biographies for the Expert Panel members as well as copies of their Charter and Operating Protocols are included in Appendix E.

ANALYSIS 3

This analysis section is accompanied by Appendix H, which presents the details of the statistical test that were used to draw the conclusions presented in this section. As noted by others (Maxim and Niebo 2001), the analysis of oil spill data is challenged by the fact that there are often many small spills and a very few large spills. Statistical analysis shows this to be a highly non-normal distribution (Appendix H1). This non-normal distribution of spill volumes makes many summary statistics, such as the average volume spilled, nearly meaningless.[1] Where the average volume is reported, the reader should consider that the average does not represent either a typical or probable spill. The average number of spills is a more meaningful statistic. Where possible, data are presented in graphical form to illustrate distributions and relationships in the data.

One example of the dominance of the large spills is shown in Figure 3-1. The top chart is percentage of spill count and total volume by regulatory category across the entire data set. The bottom chart presents the same data, excluding the two largest (200,000+ gallon) spills that occurred in 2006. The exclusion of these largest spills presents a very different graph. While these two spills represent outliers, they are included in the analysis because they represent the type of spill that the State of Alaska is trying to understand and avoid.

The North Slope spill data analysis is organized by first examining combined data from all loss-of-integrity spills, then examining spills by regulatory category, and finally by primary cause of failure. In each analysis the frequency of spills, total volume, spill size class, primary cause of failure, temporal trends, and spatial trends are considered. Other sections of the analysis consider leak rates, age of pipeline at failure, leak detection, and impacts. All spill volumes are reported in gallons.

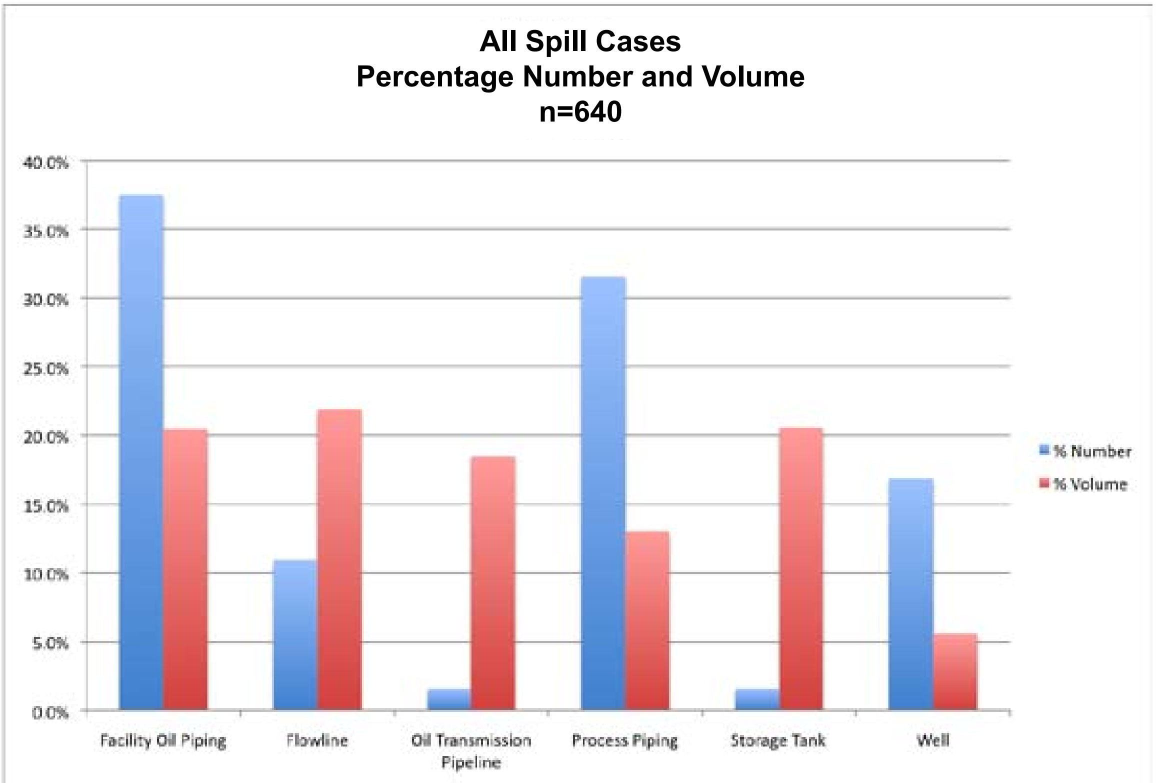
The analysis presented in this section considers whether the frequency and severity of loss-of-integrity spills from North Slope oil and gas operations is increasing over time, by looking for trends in the number and total volume of reported spills.

3.1 Analysis of Combined Loss-of-Integrity Spill Data

Six hundred forty (640) loss-of-integrity spills were reported during the analysis time period from July 1, 1995 through December 31, 2009. Table 3-1 presents the number and total volume spilled each year. The average spill frequency was 44 loss-of-integrity spills per year. The total volume of crude oil and produced water spilled was 1,200,792 gallons. Spill sizes ranged from less than one gallon to 241,038 gallons. Overall, the average spill volume was 1,915 gallons with a large standard deviation of 14,746. Statistical analysis could not distinguish significant differences in spill sizes between oil

1 Consider the arbitrary case where there are 99 spills of 10 gallons and one spill of 10,000 gallons. The average spill size is 109.9, but this says very little about the typical spill size or the probable spill size.

fields, therefore all oil fields were considered together when examining number and volume data (Appendix H2). Oil fields are compared in Section 3-4 on leak rates.



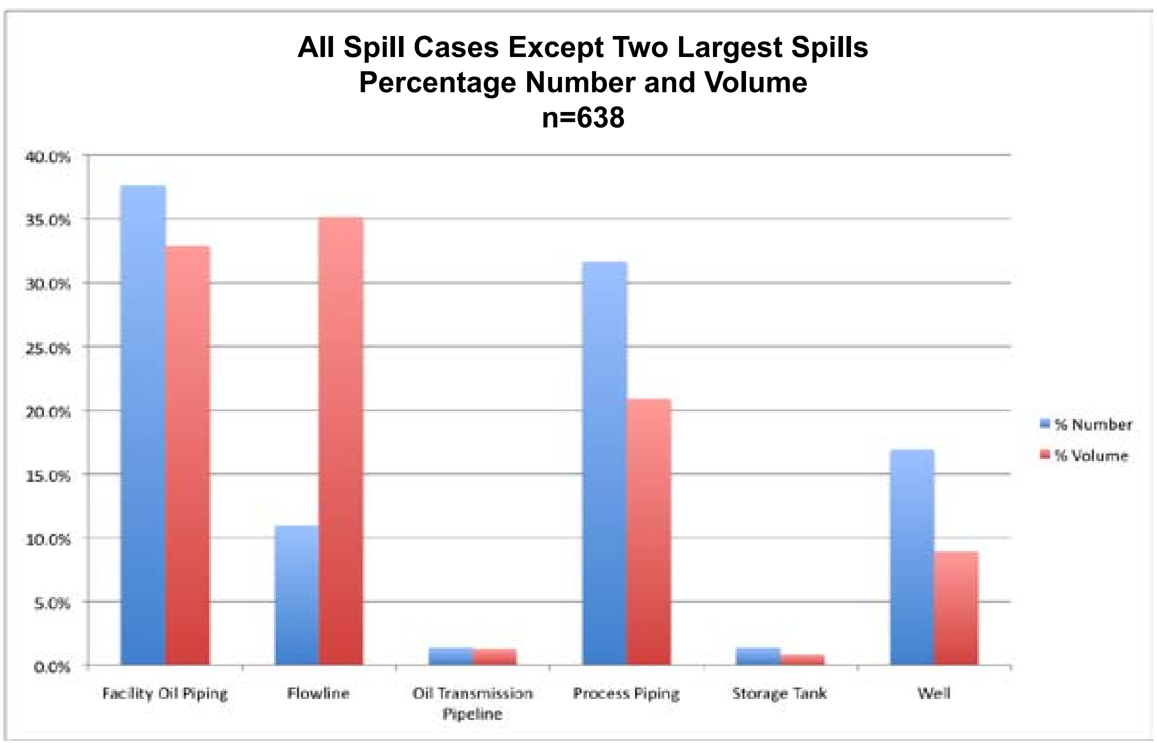


Figure 3-1. Percentage of spill number and total volume of loss-of-integrity spills from the North Slope oil production infrastructure by regulatory category with and without the two largest spills.

Table 3-1. Number and total volume (gallons) of loss-of-integrity spills reported from North Slope oil operations across all fields and regulatory categories.

Year	Number of Spills	Total Volume (gallons)
1995	21	14,944
1996	51	26,843
1997	46	18,098
1998	52	87,506
1999	35	16,642
2000	41	12,577
2001	40	105,071
2002	40	33,158
2003	50	24,452
2004	45	42,493
2005	44	62,179
2006	55	469,311
2007	35	54,583
2008	47	162,522
2009	38	70,412
Grand Total	**640**	**1,200,791**

Figure 3-2 depicts the number per year of loss-of-integrity spills across all oil fields and all regulatory categories.[2] Statistical analysis shows that the number of loss-of-integrity spills across all North Slope oil infrastructure shows no significant trend over the analysis time period. Figure 3-3 depicts numbers of spills greater than 1,000 gallons plotted by year. The average number of spills greater than 1,000 is 4.8 spills per year. Even when considering just the 70 largest spills (≥ 1,000 gallons), the number of spills shows no significant trend over the analysis time period (Appendix H2).

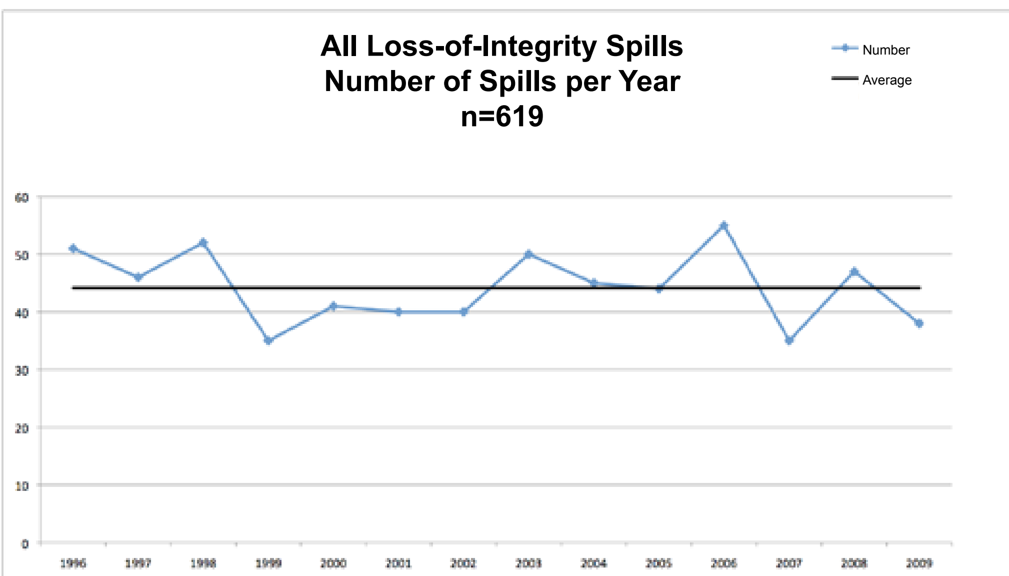


Figure 3-2. Annual number of spills for all regulatory categories loss-of-integrity spills reported by North Slope oil and gas operators across all years.

2 Note that the spills from the partial year 1995 are not included when plotting spills across time; therefore, the starting number is 619, because the 21 spills from the partial year 1995 have been removed.

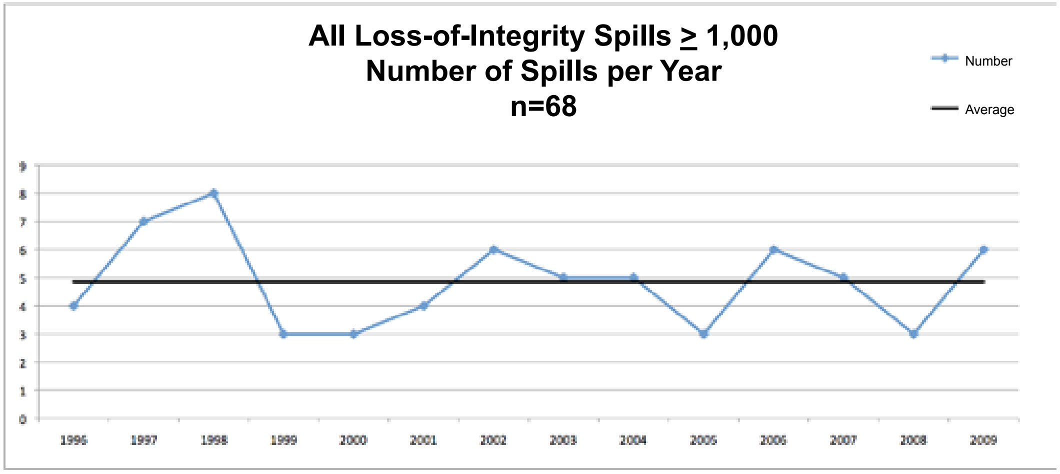


Figure 3-3. Annual number of spills for loss-of-integrity spills ≥ 1,000 gallons reported by North Slope oil and gas operators across all years.

Figure 3-4 depicts a bar graph of total spill volume by year with an overlaid scatter plot of actual spill events plotted over the same time period. Note that the two largest spill events occurred in 2006 and 8 of the 12 spills greater than 10,000 gallons occurred in the years 2004 to 2009. This graph shows evidence of a trend of increasing spill quantity over the analysis time period. However, this trend is dependent on the two spills in 2006 and statistical tests are inconclusive in determining whether spill volume is increasing over time.

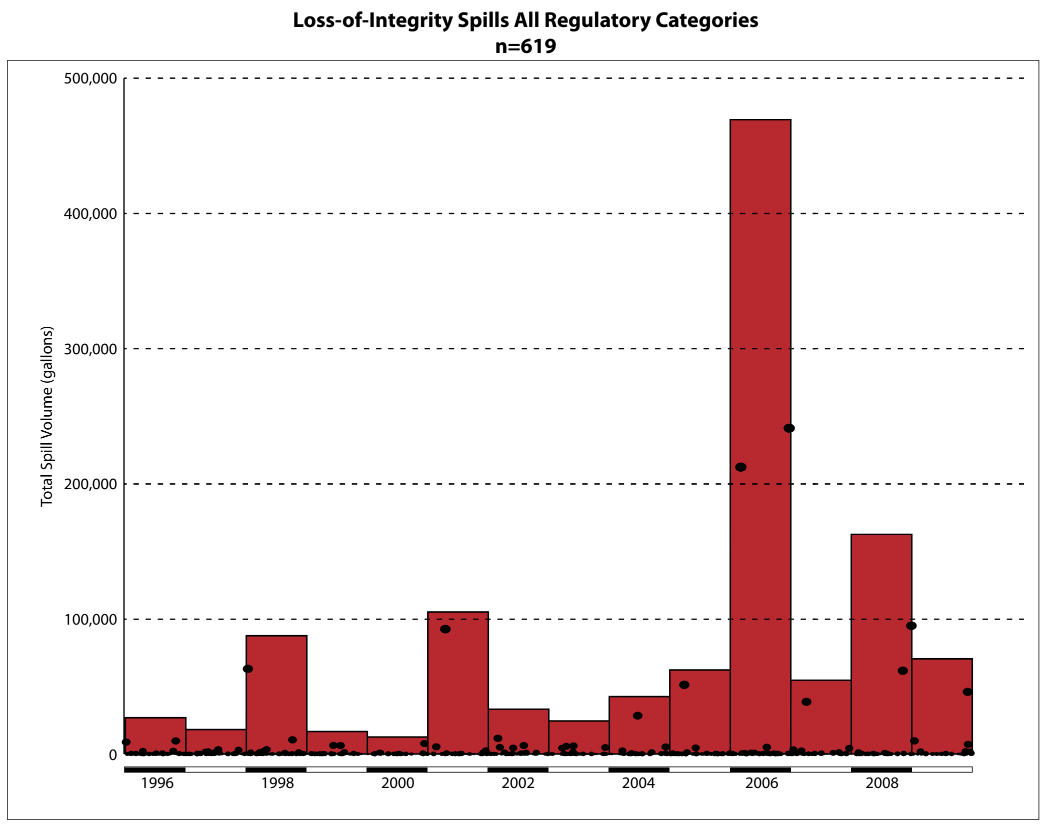


Figure 3-4. Bar graph of total spill volume (gallons) by year and scatter plot of actual spill events, all North Slope loss-of-integrity spills.

Examining reported spills by size class helps with understanding the severity of spills. Table 3-2 presents the number and total volume of spills by spill size category. Figure 3-5 depicts the same data, which shows again that a few large spills account for the vast majority of the total volume spilled. The two spills over 100,000 gallons are just 0.3% of the total number of spills, but account for 38% of the total volume spilled. The 13 spills greater than 10,000 gallons represent 2% of the number of spills, but account for 80% of the total volume spilled. The details of these 13 spills are contained in Appendix D1.

Table 3-2. Percentage of total volume (gallons) of loss-of-integrity spills reported by size class from North Slope oil operations across all fields and regulatory categories

Size Class (gallons)	≤ 10	≥ 10 – < 100	≥ 100 – < 1,000	≥ 1,000 - < 10,000	≥ 10,000 - < 100,000	≥ 100,000	Total
Number	216	201	153	57	11	2	640
Percent	33.8%	31.4%	23.9%	8.9%	1.7%	0.3%	
Volume (gallons)	648	7,377	47,059	181,613	510,805	453,290	1,200,791
Percent	0.1%	0.6%	3.9%	15.1%	42.5%	37.7%	

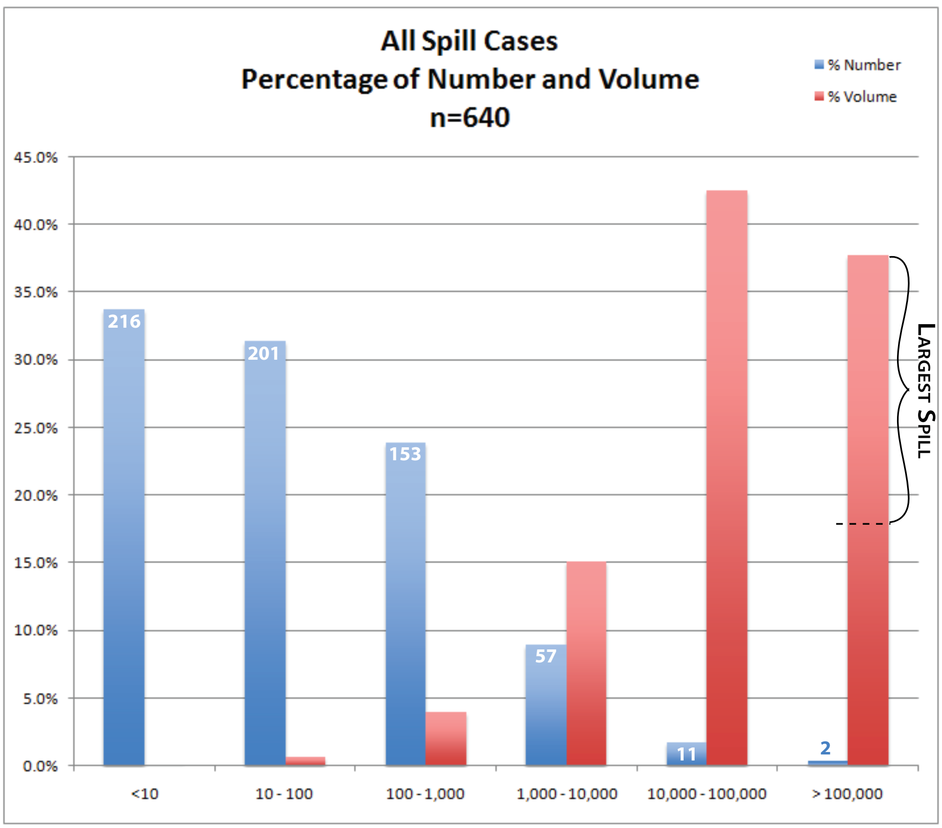


Figure 3-5. Percentage of number and total volume (gallons) of spill cases from loss-of-integrity spills by size class.

Table 3-3 presents the number and total volume by year of the 70 largest spills (≥ 1,000 gallons). The 70 spills greater than 1,000 gallons represent 11% of the number of spills, but account for 95% of the total volume spilled. A relatively small number of large spills are by far the greatest contributors to total spill volume (Appendix H1).

Table 3-3. Number and total volume (gallons) of loss-of-integrity spills greater than 1,000 gallons reported from North Slope oil operations across all fields and regulatory categories.

Year	Number of Spills	Total Volume (gallons)
1995	2	13,860
1996	4	22,933
1997	7	14,364
1998	8	83,680
1999	3	14,034
2000	3	9,754
2001	4	101,604
2002	6	29,629
2003	5	22,592
2004	5	38,380
2005	3	57,058
2006	6	461,502
2007	5	49,935
2008	3	157,806
2009	6	68,577
Grand Total	**70**	**1,145,708**

Table 3-4 presents the primary cause of three spill sets from the loss-of-integrity spills where cause was recorded. The first set contains all spill cases, the second set contains spill cases greater than or equal to 1,000 gallons, and the third set contains spill cases greater than or equal to 10,000 gallons. Figure 3-6 depicts the relative contribution of selected primary causes to each set of spill sizes.[3] The relative contribution of valve/seal failures and operator error decreases as spill size increases and the relative contribution of failures due to internal corrosion increases as spill size increases. Statistical analysis shows that spill size is highly dependent upon cause (Appendix H3). The conclusion drawn from this analysis is that valve/seal failure is the most frequent cause of loss-of-integrity spills overall and internal corrosion is the most frequent cause of spills ≥ 10,000 gallons.

Statistical examination of the data for cyclical behavior found strong evidence of periodicity in the data (Appendix H2). The maximum numbers of spills occur in June. One possible explanation of this is that more spills are discovered in June because of longer daylight hours and a decrease in obscuring snow and ice results in a higher rate of spill discovery.

Figure 3-7 maps the distribution of all loss-of-integrity spills across the North Slope.

Taken together, loss-of-integrity spills across all regulatory categories and oil fields do not exhibit an increase in the number or severity of spills over time.

3 Spills where causal data was not available are excluded from this graph. Note that "material failure of pipe or weld" was included as a cause in the NSS database and was one of the leading contributing causes in initial analysis of the data; however, based on Expert Panel review and discussion, material failure was ignored for causal analysis since this cause category is too vague to provide any meaningful information. For example, corrosion, erosion, and thermal expansion are all types of material failure. Spills due to corrosion, but unknown as to internal or external were also excluded from this graph.

Table 3-4. Primary cause of three-spill size sets for loss-of-integrity spills reported from North Slope oil operations across all fields and regulatory categories.[4]

	All Cases n=501		All Cases ≥ 1,000 gallons n=59		All Cases ≥ 10,000 gallons n=10	
Primary Cause	**Number**	**%**	**Number**	**%**	**Number**	**%**
Valve/Seal Failure	249	40.0%	20	23.0%	2	11.1%
Operator Error	84	13.5%	5	5.7%	0	0.0%
Internal Corrosion	54	8.7%	12	13.8%	6	33.3%
Thermal Expansion	39	6.3%	5	5.7%	1	5.6%
External Corrosion	25	4.0%	9	10.3%	1	5.6%
Overpressure	24	3.9%	2	2.3%	1	5.6%
Erosion	20	3.2%	4	4.6%	0	0.0%
Construction, Installation or Fabrication Related	11	1.8%	2	2.3%	0	0.0%
Vibration (wind-induced/slugging)	5	0.8%	2	2.3%	0	0.0%
3rd Party Action	1	0.2%	0	0.0%	0	0.0%

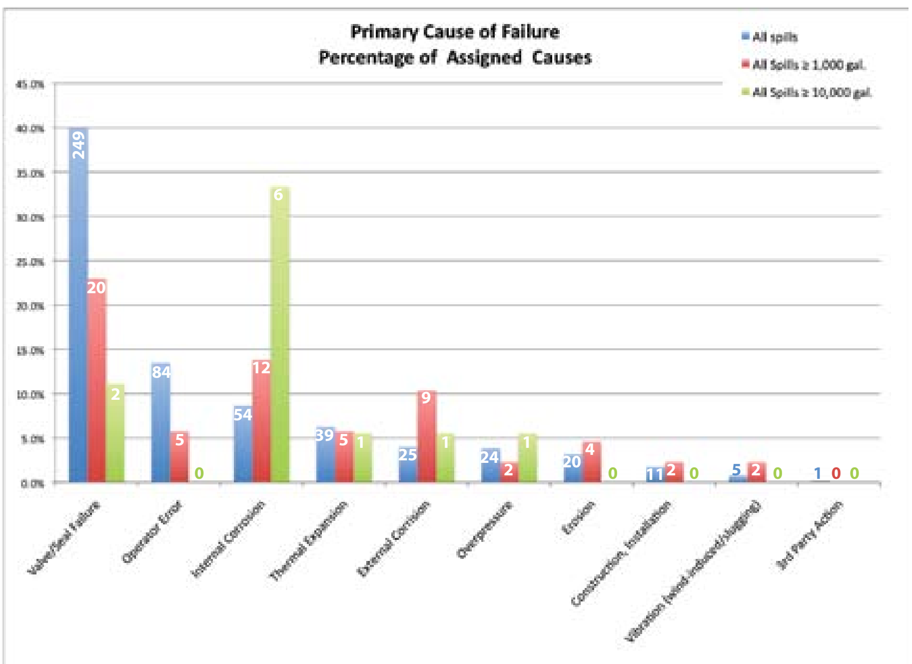


Figure 3-6. Primary cause of failure assigned to three sets of spill size classes from loss-of-integrity spills reported by North Slope oil and gas operators during the study period.

3.2 Analysis of Spill Data by Regulatory Category

The six regulatory categories used for this analysis are defined in Table 2-2 (page 16). All spill cases were assigned to the appropriate regulatory category based on a review of the final spill report and the researcher's best professional judgment. Additionally, spill cases associated with the flowlines and oil transmission pipeline categories were reviewed by the oil operator with responsibility for the case.

4 Note that n is the number of spill cases. Some cases have more than one primary cause, so the number of cause assignment exceeds the number of cases.

Table 3-5 presents the number and total volume of 640 loss-of-integrity spills by regulatory category. Figure 3-8 depicts the percentage number and percentage total volume spilled by regulatory category. Figure 3-9 depicts the distribution of number of spills by year by regulatory category. Trends across time are discussed in Sections 3.2.1 through 3.2.6.

Table 3-5. Number of spills and total volume (gallons) released by regulatory category for North Slope loss-of-integrity spills.

Regulatory Category	Number of Spills	Total Volume (gallons)
Storage Tank	10	247,137
Oil Transmission Pipeline	9	217,439
Flowline	71	267,102
Facility Oil Piping	240	246,132
Process Piping	202	156,345
Well	108	66,638
Grand Total	**640**	**1,200,792**

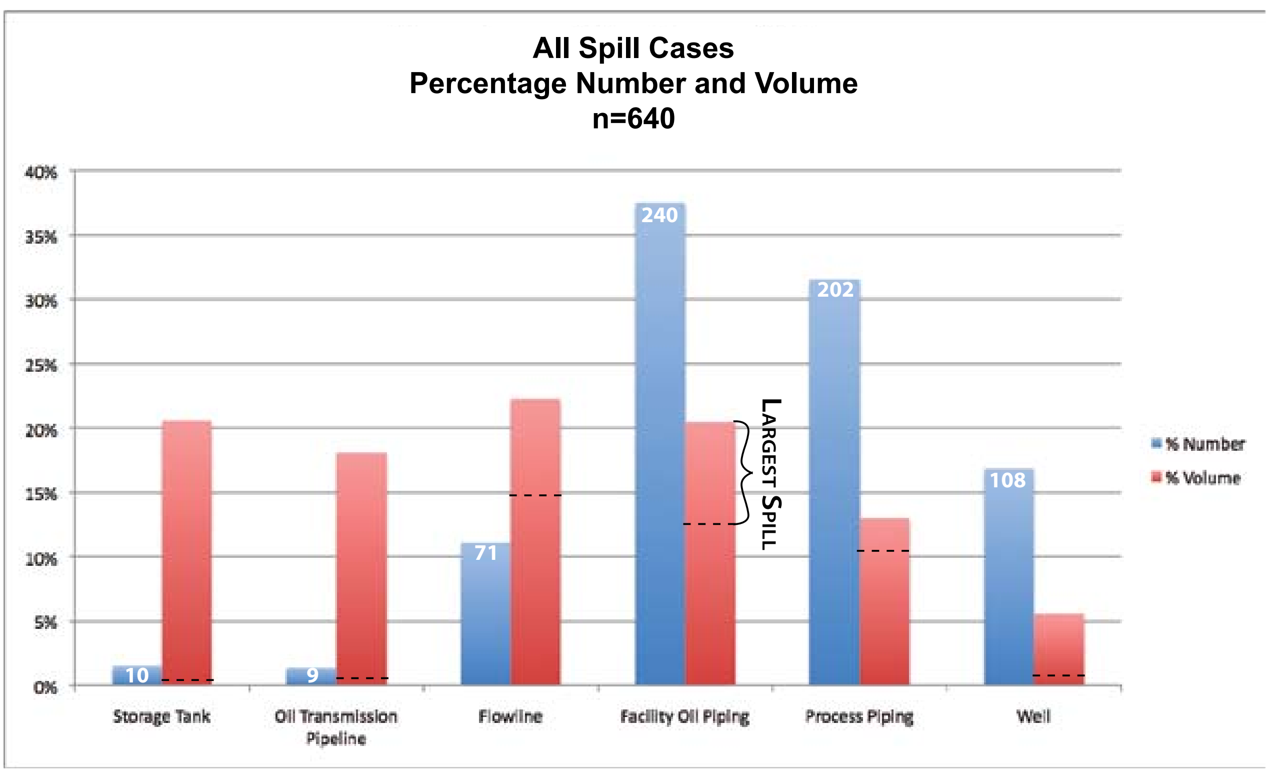


Figure 3-8. Percentage of number and total volume (gallons) of spill cases from loss-of-integrity spills by regulatory category.

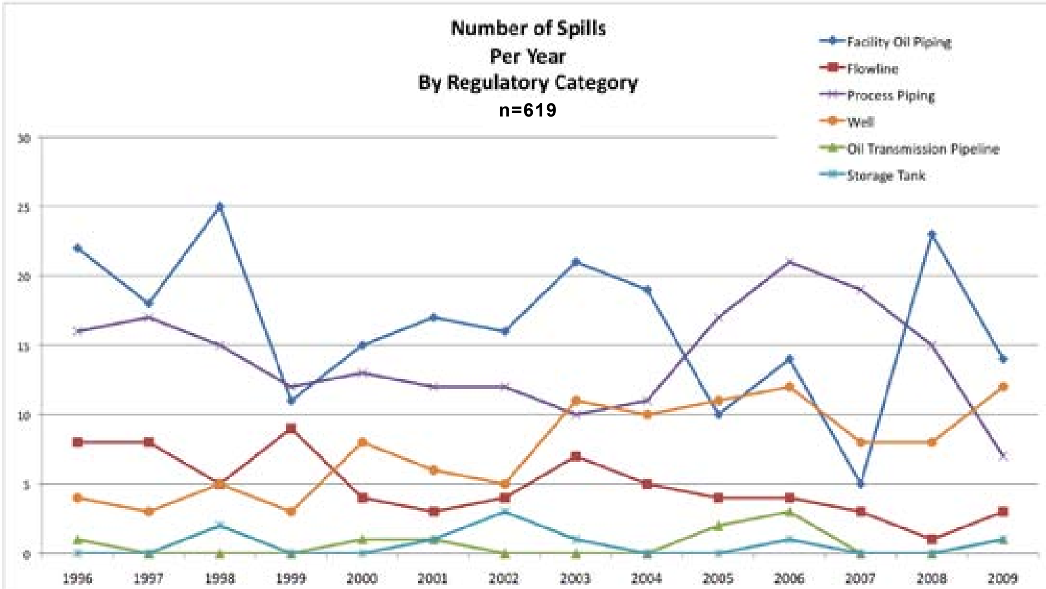


Figure 3-9. Number of loss-of-integrity spills reported by North Slope oil and gas operators by year by regulatory category.

3.2.1 Flowlines

Flowlines account for the most mileage of pipelines on the North Slope, with 378 pipelines extending over 800 pipeline miles. These lines range from 6" to 36" in diameter. Figure 3-10 maps the distribution of flowline loss-of-integrity spills across the North Slope. A total of 71 loss-of-integrity flowline spills were identified during the study period. There were an average of 4.9 spills per year. Flowlines were the largest contributor (22%) to the total volume spilled during the study. A total volume of 267,102 gallons was spilled in the flowline category.

Flowline spills were further divided by service type into the following sub-categories:

- Operational spills from three-phase flowlines (3P FL) carrying oil, gas, and produced water;
- Operational spills from produced water flowlines (PW FL) carrying produced water or seawater; and
- Maintenance activity spills for either three-phase or produced water flowlines, usually related to pigging activities.

Table 3-6 presents the annual number of spills and total volume for each of these categories. Figure 3-11 depicts the percentage of the number and total volume for each of these flowline sub-categories. These data indicate that nearly half (35) of the flowline spills are related to maintenance activities but these maintenance spills account for less than 10% of the total volume spilled. Two spills from the produced water flowline category account for 58% of the total volume of flowline spills. Statistical analysis demonstrates that the number of spills are significantly different between these three sub-categories (Appendix H4.1).

Table 3-6. Number of spills and total volume (gallons) released by flowline subcategory by year for North Slope flowline loss-of-integrity spills.

	MAINTENANCE ACTIVITY		THREE PHASE		PRODUCED WATER	
Year	Number of Spills	Total Volume (gallons)	Number of Spills	Total Volume (gallons)	Number of Spills	Total Volume (gallons)
1995	2	549	1	25	0	0
1996	2	8,946	4	78	2	2,271
1997	5	5,511	3	2,009	0	0
1998	3	2,186	0	0	2	73,500
1999	8	2,603	0	0	1	6,300
2000	2	650	2	635	0	0
2001	1	2	1	420	1	92,400
2002	2	97	2	970	0	0
2003	2	194	4	6,093	1	5
2004	2	282	2	155	1	5,250
2005	3	1,327	1	16	0	0
2006	2	290	1	700	1	5
2007	1	105	2	5,586	0	0
2008	0	0	1	0	0	0
2009	0	0	3	47,942	3	0
Grand Total	**35**	**22,742**	**27**	**64,629**	**9**	**179,731**

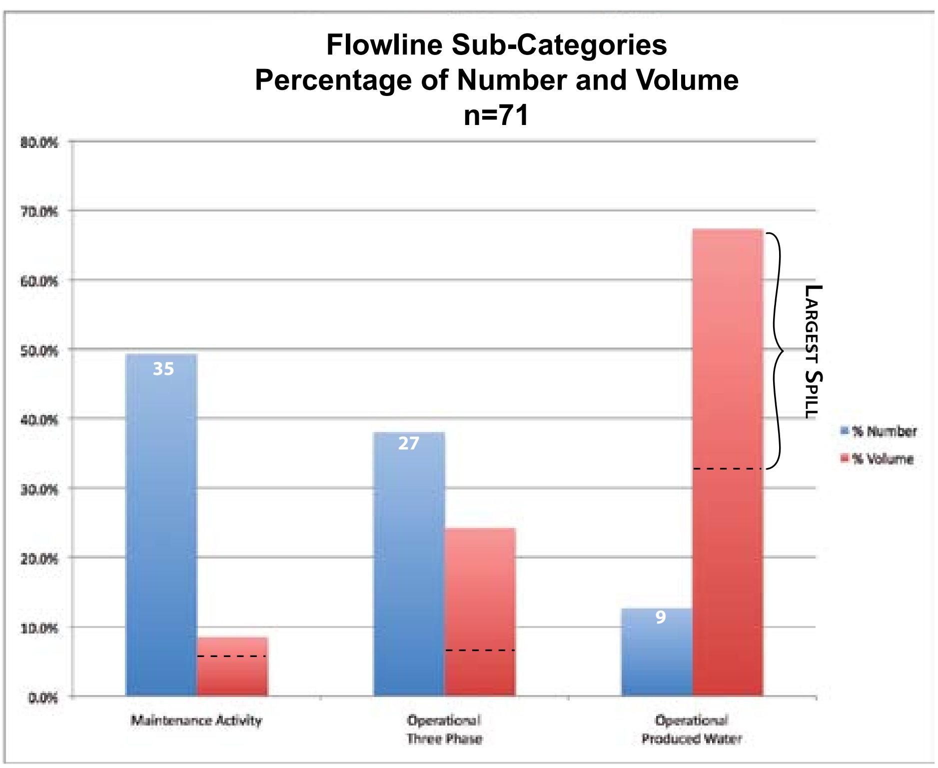


Figure 3-11. Percentage of the number and total volume (gallons) for three flowline categories: maintenance activity, three phase, and produced water.

Because of the sparse data and the similarity of service, the three-phase and produced water data flowline spills were combined into a operational flowline spill sub-category and examined separately from maintenance activity data. The operational flowline spill sub-category includes all spills except those that occurred during a maintenance activity.

Operational Flowline Spills

Operational flowline leaks are spill cases that were not associated with maintenance activities, such as pigging. There were 36 operational leaks resulting in a total spill volume of 244,360 gallons. These spills occurred from 29 specific flowlines: 7 flowlines experienced 2 spills each; 22 flowlines experienced one leak each, and 349 flowlines did not experience any spills during the study period. Figure 3-12 depicts operational spills ranked by spill size class. These data reveal that the four spill cases over 10,000 gallons account for 87% of the total volume spilled and that the 12 cases over 1,000 gallons account for nearly 97% of the total volume. Overall, a few severe spills make up most of the total volume of operational flowline spills.

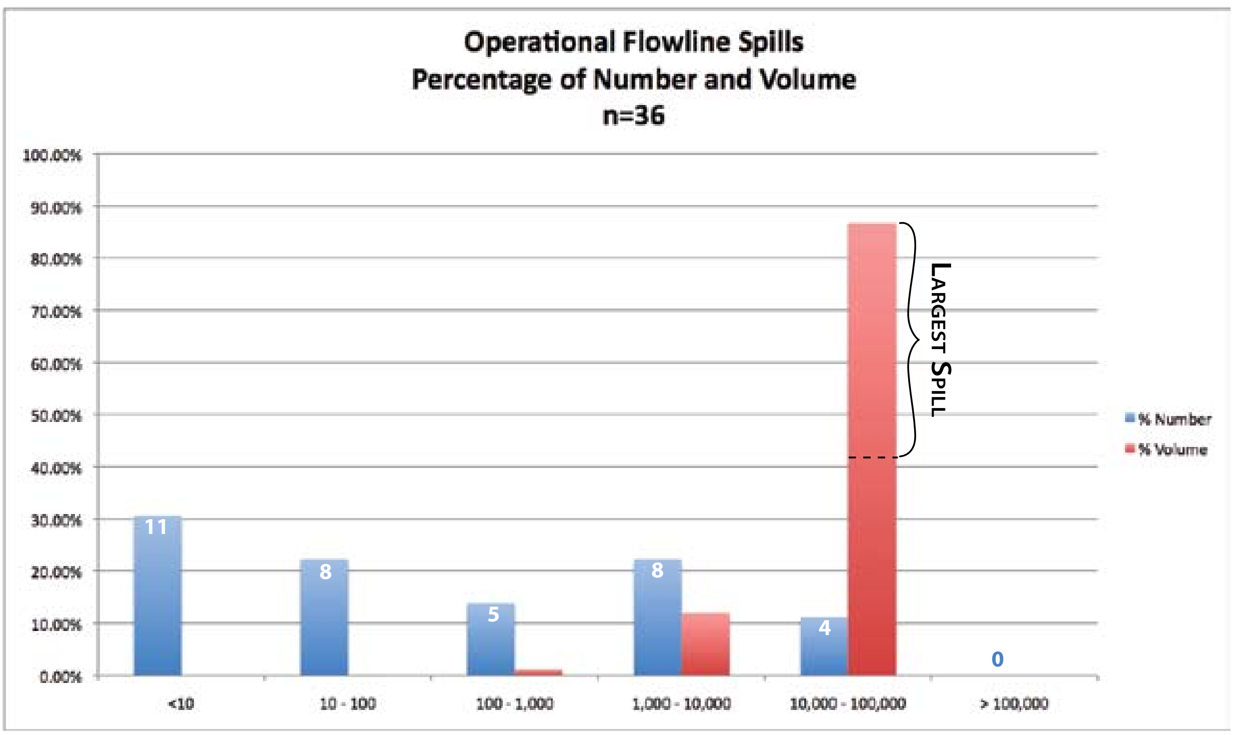


Figure 3-12. Number and volume of operational flowline spills by spill class.

Table 3-7 and Figure 3-13 present the primary cause of failure breakdown of operational flowline spills. External corrosion was the most common cause attributed to operational flowline leaks (15), followed by valve/seal failure (8), and thermal expansion (5). Internal corrosion, thermal expansion and vibration accounted for 3 spills each. Analysis of total volume by cause was not considered informative because it was dominated by single large spill cases.

Table 3-7. Primary cause of failure for operational flowline spills.[5]

OPERATIONAL FLOWLINE SPILLS n=34	
Primary Cause	Number
External Corrosion	15
Valve/Seal Failure	8
Thermal Expansion	5
Internal Corrosion	3
Vibration (wind-induced/slugging)	3
Overpressure	3
Construction, Installation or Fabrication Related	1
Operator Error	1
Erosion	0

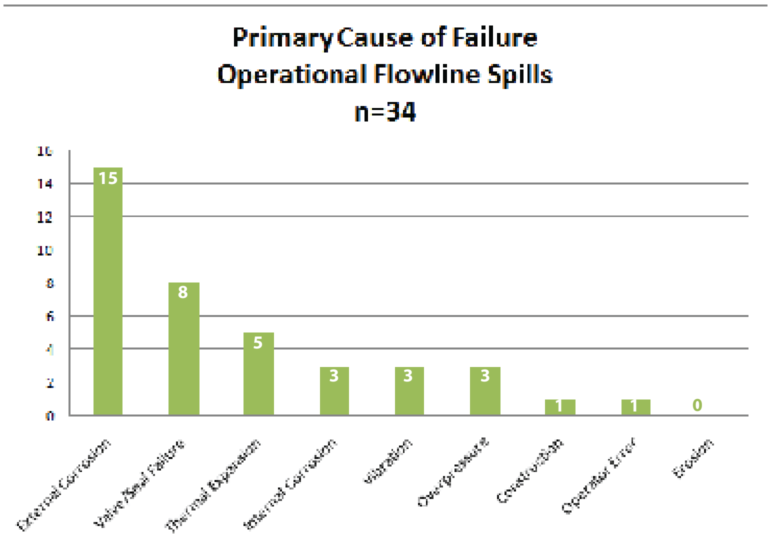


Figure 3-13. Primary cause of failure for operational flowline spills.

Figure 3-14 depicts the number of operational flowline spills by year. The average number of spills from this subcategory is 2.5 spills per year. Figure 3-15 depicts a bar graph of total spill volume by year with an overlaid scatter plot of actual spill events plotted over the same time period. Graphical analysis of the number of spills and the total volume spilled for operational flowlines indicates no trend over the analysis time period.

Spills from this subcategory occur at a relatively low frequency, but can have a high severity when they do occur.

Maintenance Activity Flowline Spills

Maintenance activity flowline spill cases are associated with maintenance activity, such as pigging. There were 35 maintenance activity flowline leaks resulting in a total spill volume of 22,742 gallons. Figure 3-16 depicts operational maintenance activity flowline spills assigned by spill size class. These

5 Note that n is the number of spill cases. Some cases have more than one primary cause, so the number of cause assignment exceeds the number of cases.

data reveal that there are no spill cases over 10,000 gallons and that the 5 cases over 1,000 gallons account for over 75% of the total volume. Flowline maintenance activity spills are broadly distributed across size classes.

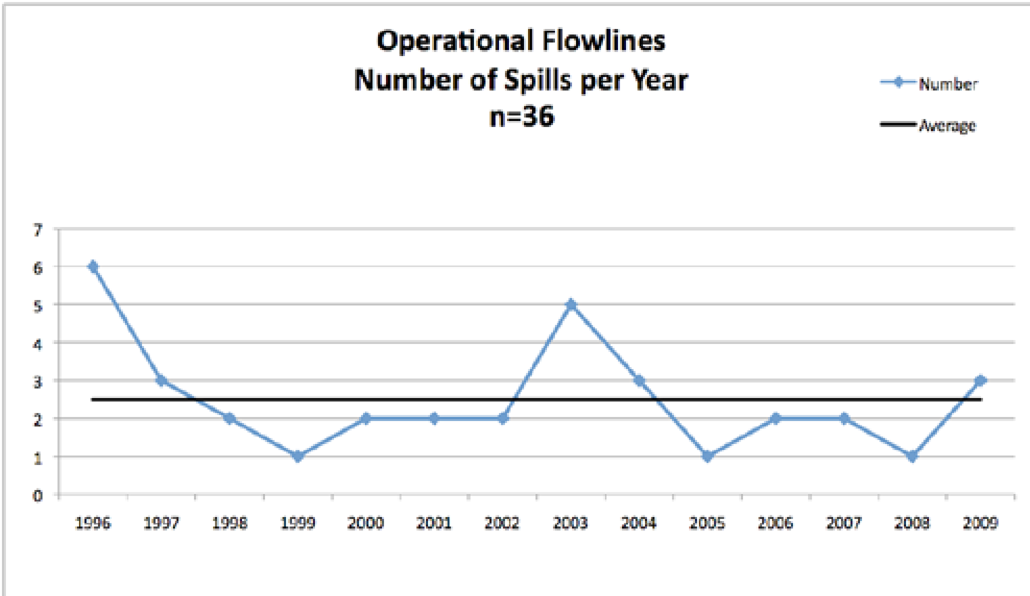


Figure 3-14. Number of operational flowline loss-of-integrity spills reported by North Slope oil and gas operators by year with the average across all years.

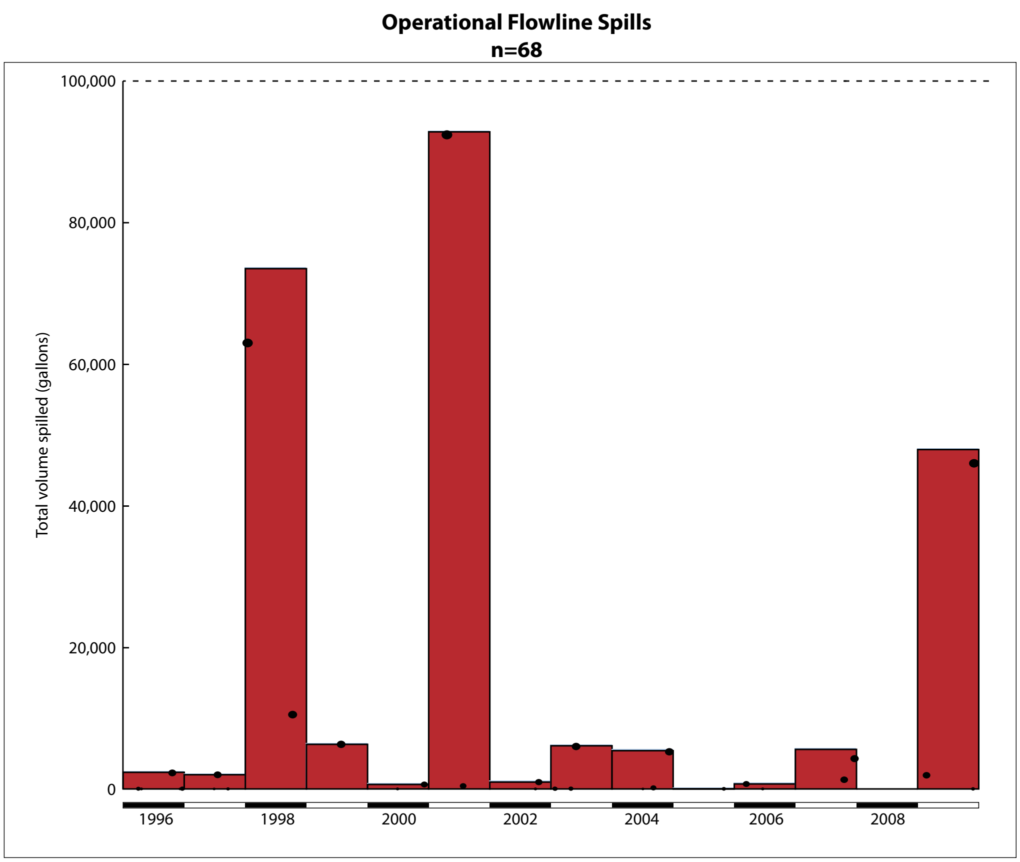


Figure 3-15. Bar graph of total spill volume (gallons) by year and scatter plot of actual spill events, all operational flowline loss-of-integrity spills.

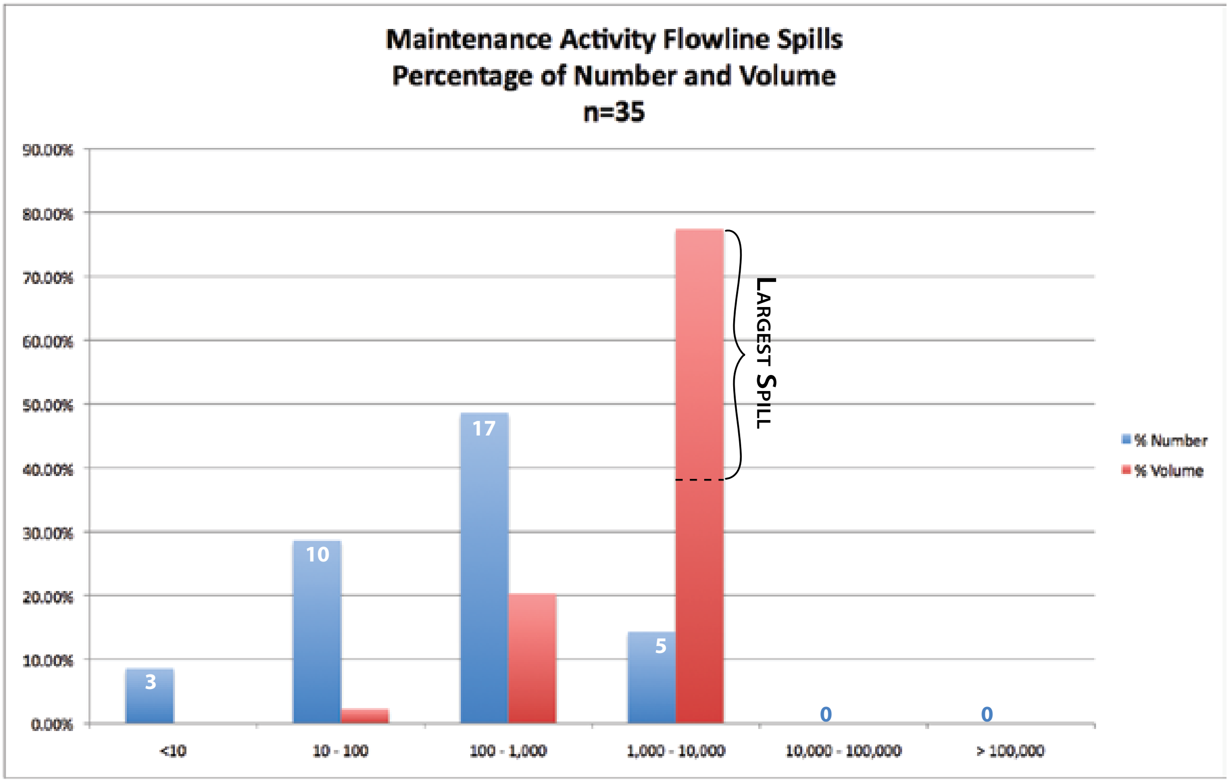


Figure 3-16. Number and volume of maintenance activity flowline spill cases by spill size class.

Table 3-8 and Figure 3-17 present the primary cause breakdown of maintenance activity flowline spills. Valve/seal failure was by far the greatest cause of spills (25), followed by operator error (5), internal corrosion (4), and overpressure (3). Material failure, construction defects, and erosion each had 1 spill.

Table 3-8. Primary cause of failure for maintenance activity flowline spills.[6]

MAINTENANCE ACTIVITY FLOWLINE SPILLS n=34	
Primary Cause	**Number**
Valve/Seal Failure	25
Operator Error	5
Internal Corrosion	4
Overpressure	3
Erosion	1
Construction, Installation or Fabrication Related	1
External Corrosion	0
Thermal Expansion	0
Vibration (wind-induced/slugging)	0
3rd Party Action	0

6 Note that n is the number of spill cases. Some cases have more than one primary cause, so the number of cause assignment exceeds the number of cases.

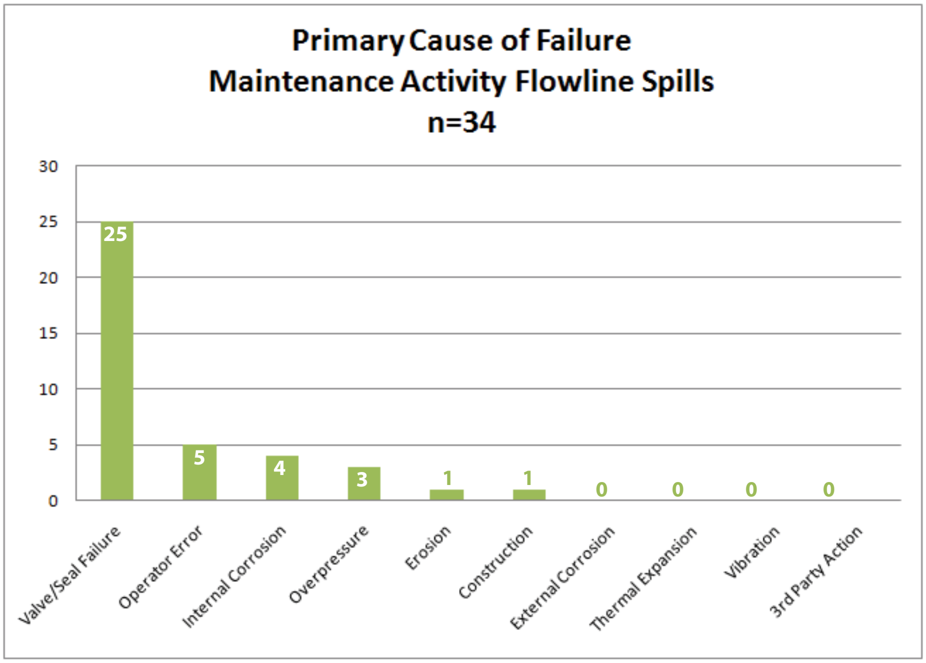


Figure 3-17. Primary cause of failure for maintenance activity flowline spills.

Figure 3-18 depicts the number of maintenance activity flowline spills by year. The average number of spills from this sub-category is 2.4 spills per year. Figure 3-19 depicts a bar graph of total spill volume by year with an overlaid scatter plot of actual spill events plotted over the same time period. Graphical analysis of the number of spills and the total volume spilled for maintenance activity flowlines indicates a downward trend over the analysis time period. This subcategory has contributed little to the frequency or severity of spills during the past five years of the study period.

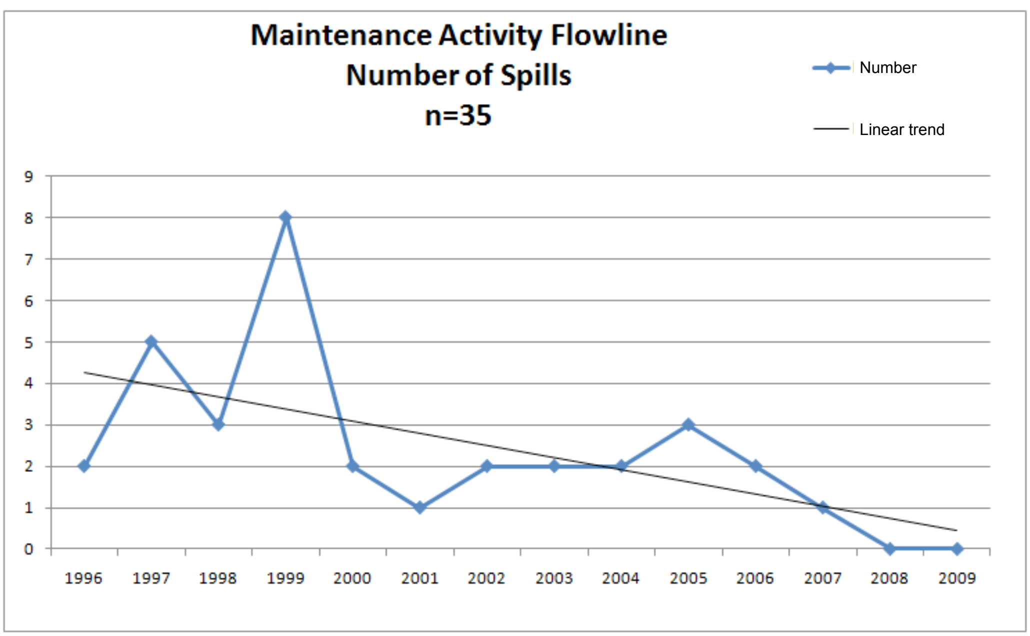


Figure 3-18. Average number of maintenance activity flowline loss-of-integrity spills reported by North Slope oil and gas operators by year with the trend line across all years.

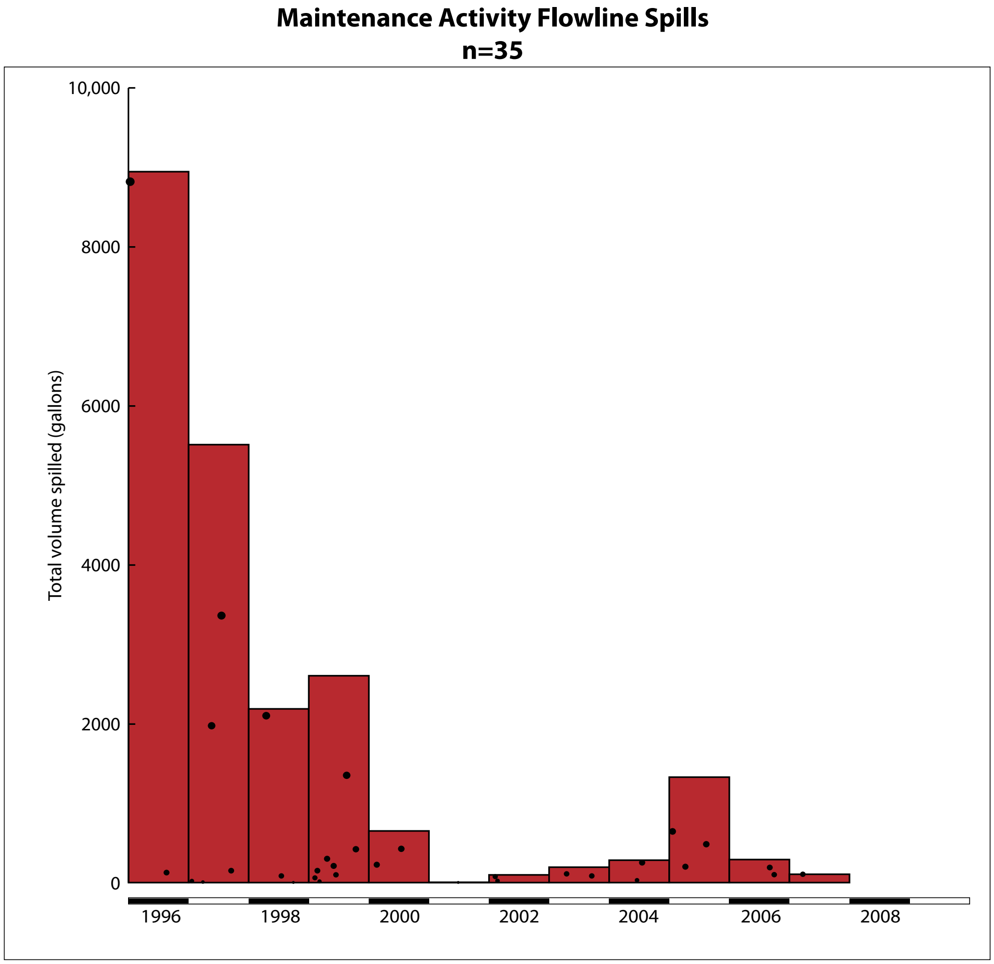


Figure 3-19. Bar graph of total spill volume (gallons) by year and scatter plot of actual spill events, all maintenance activity flowline loss-of-integrity spills.

3.2.2 Oil Transmission Pipelines

There are 16 oil transmission pipelines extending over 177 pipeline miles on the North Slope. These lines range from 6" to 34" in diameter. Figure 3-20 maps the distribution of oil transmission pipeline loss-of-integrity spills across the North Slope. A total of 9 loss-of-integrity oil transmission pipeline spills were identified during the analysis time period resulting in a total volume of 217,439. There were an average of 0.6 spills per year from oil transmission pipelines.

Oil transmission pipelines spills were further divided by service type into the following subcategories:

- Operational spills from oil transmission; and
- Maintenance activity spills (related to pigging).

Table 3-9 presents the annual spill number and total for both of these categories. Figure 3-21 depicts the number and total volume of spills for each of these categories. One oil transmission pipeline spill accounts for 99.9% of the total volume spilled; the second largest spill in this category was 5,040 gallons, the other seven spills were less than 100 gallons each.

Table 3-9. Annual number of spills and total volume (gallons) for maintenance activity and operational oil transmission pipeline categories.

	MAINTENANCE ACTIVITY		OPERATIONAL	
Year	Number of Spills	Total Volume (gallons)	Number of Spills	Total Volume (gallons)
1995	0	0	0	0
1996	1	84	0	0
1997	0	0	0	0
1998	0	0	0	0
1999	0	0	0	0
2000	0	0	1	2
2001	0	0	1	1
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	1	4	1	1
2006	0	0	3	217,342
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	1	5
Grand Total	**2**	**88**	**7**	**217,351**

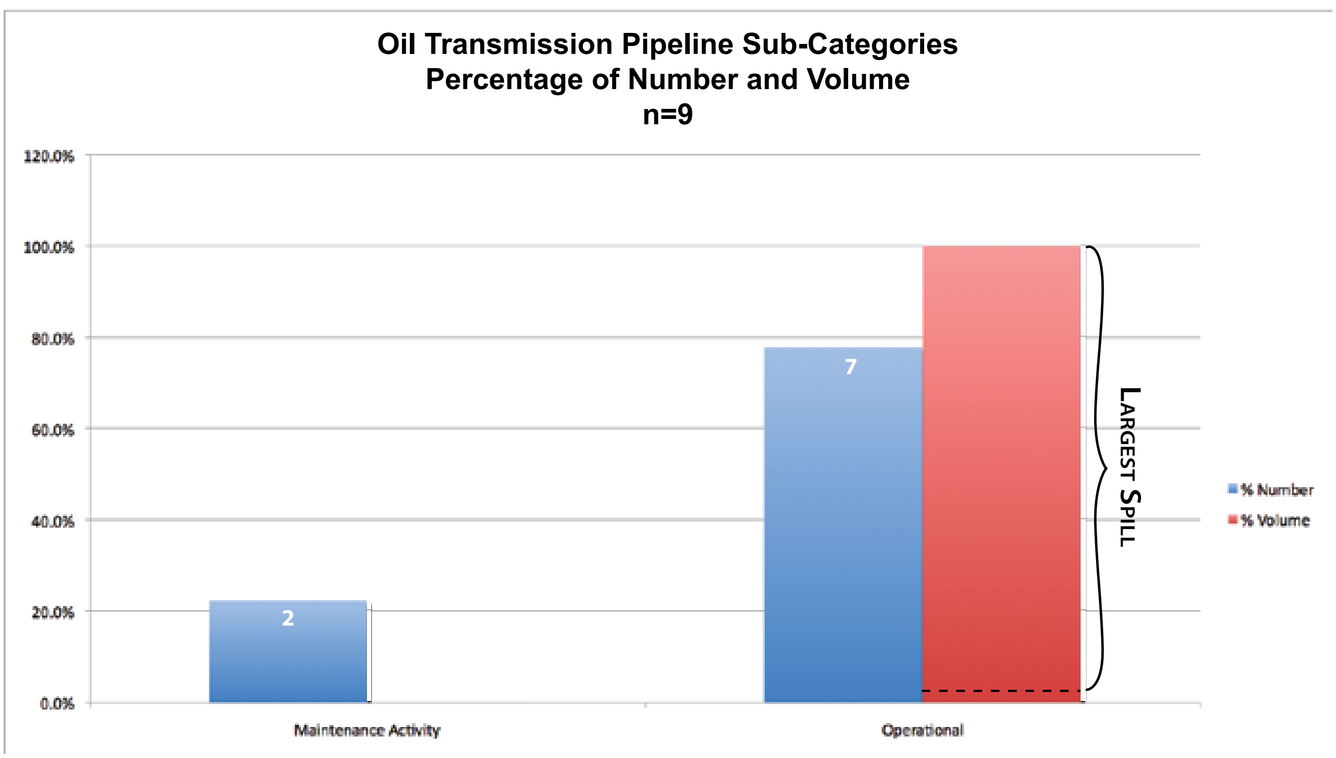


Figure 3-21. Percentage of number and volume of spills from oil transmission pipelines, maintenance activity and operational.

Operational Oil Transmission Pipeline Leaks

Oil transmission pipeline leaks are spill cases that were not associated with maintenance activities, such as pigging. There were 7 oil transmission pipeline leaks from 16 oil transmission pipelines on the North Slope; no pipelines have experienced more than a single spill. Figure 3-22 depicts the percentage of the number and total volume by size class for operational oil transmission pipeline leaks. Nearly the entire total volume of operational oil transmission pipeline leaks are accounted for by a single spill in 2006 of 212,252 gallons.

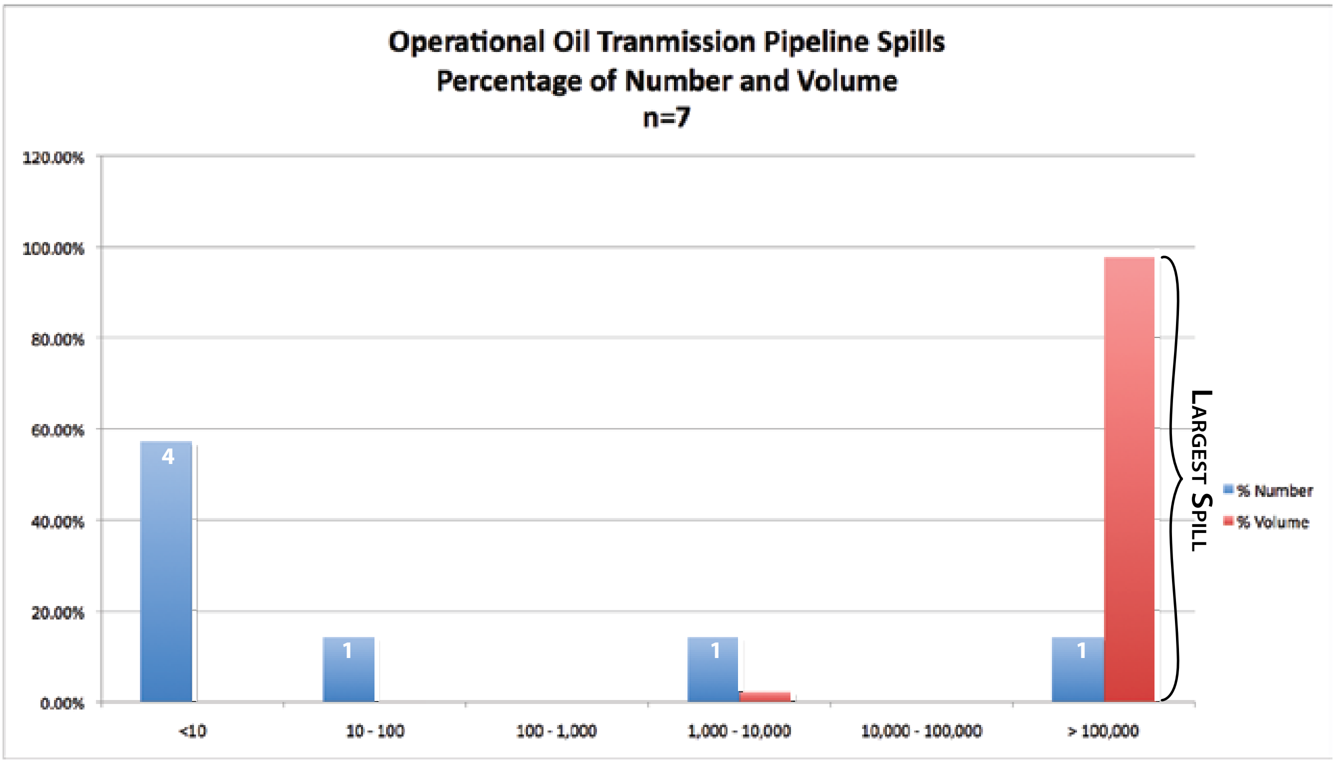


Figure 3-22. Number and volume of operational oil transmission pipeline spill cases by spill class.

Table 3-10 and Figure 3-23 present the primary cause breakdown of oil transmission pipeline leaks. Valve/seal failure was the greatest cause of spills (4), followed by internal corrosion (2), and operator error (2). Material failure, thermal expansion, and construction related failure each accounted for 1 spill each. The single largest spill of 212,252 gallons was caused by internal corrosion.

Figure 3-24 depicts the number of operational oil transmission pipeline spills by year. The average number of spills from this subcategory is 0.5 spills per year. Figure 3-25 depicts a bar graph of total spill volume by year with an overlaid scatter plot of actual spill events plotted over the same time period. Graphical analysis of the number of spills and the total volume spilled for operational flowlines indicates no trend over the analysis time period.

The single large spill in 2006 is a major contributor to the severity of spills, but the frequency and severity of all other spills from this category has been very low.

Table 3-10. Primary cause of failure for operational oil transmission pipeline spills.[7]

OPERATIONAL OIL TRANSIMISSION PIPELINE SPILLS n=7	
Primary Cause	**Number**
Valve/Seal Failure	4
Internal Corrosion	2
Operator Error	2
Thermal Expansion	1
Construction, Installation or Fabrication Related	1
External Corrosion	0
Erosion	0
Vibration (wind-induced/slugging)	0
Overpressure	0
3rd Party Action	0

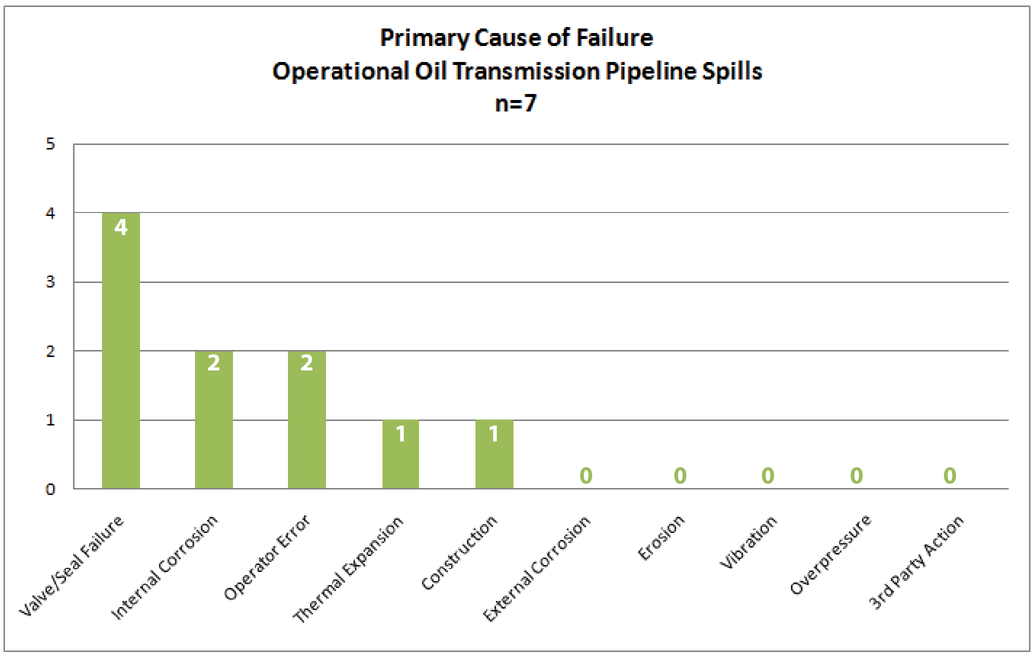


Figure 3-23. Primary cause of failure for operational oil transmission pipeline spills.

Maintenance Activity Oil Transmission Pipeline Spills

Maintenance activity oil transmission pipeline spill cases are associated with maintenance activities, such as pigging. Only two spill cases occurred in this sub-category, so summary statistics are not meaningful. One spill of 84 gallons in 1996 was the result of operator error and the other spill of 4 gallons in 2005 was the result of a valve/seal failure. Maintenance activity oil transmission pipeline spills are not a significant contributor to either frequency or severity of loss-of-integrity spills on the North Slope.

7 Note that n is the number of spill cases. Some cases have more than one primary cause, so the number of cause assignment exceeds the number of cases.

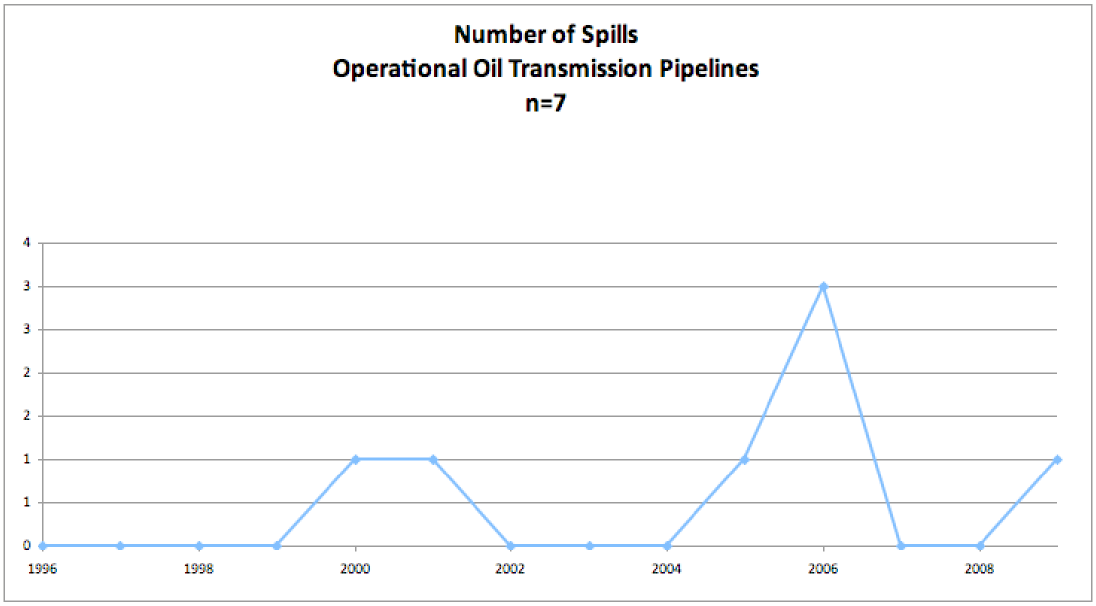


Figure 3-24. Average number of operational oil transmission pipeline loss-of-integrity spills reported by North Slope oil and gas operators by year.

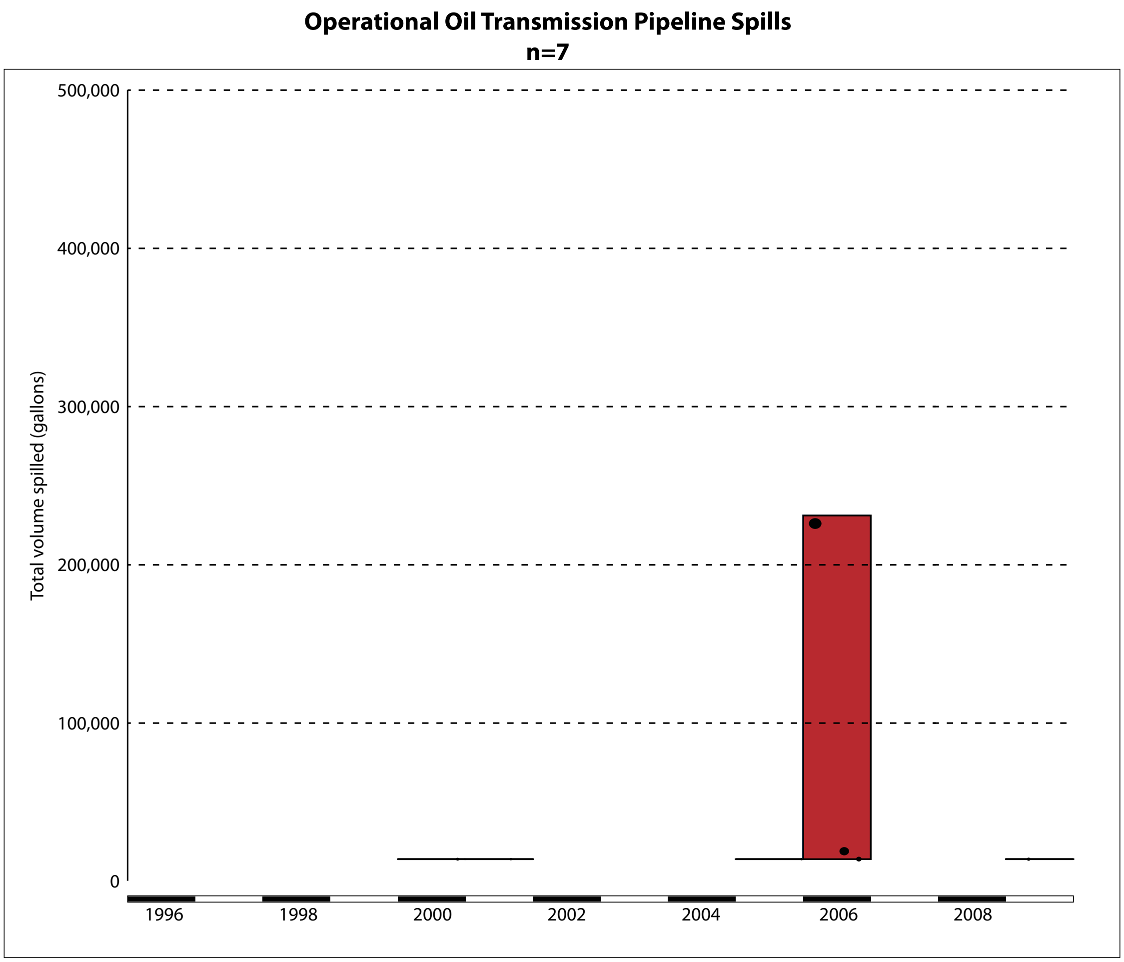


Figure 3-25. Bar graph of total spill volume (gallons) by year and scatter plot of actual spill events, all operational oil transmission pipeline loss-of-integrity spills.

3.2.3 Facility Oil Piping

Table 3-5 (page 28) shows that the regulatory category with the largest number of spill cases is facility oil piping with 240 spill cases, which represents 38% of the total number of loss-of-integrity spills. The volume spilled from facility oil piping was 246,132 gallons or 20% of the total volume spilled across all spills in the study. Thus, facility oil piping is second only to flowlines in the total volume spilled. Facility oil piping also exhibits the highest spill frequency of 16.6 spills per year. Figure 3-26 maps the spatial distribution of facility oil piping spills. Table 3-11 presents the annual spill number and total volume of loss-of-integrity spills in the facility oil piping category.

Table 3-11. Annual spill number and total volume (gallons) for loss-of-integrity spills in the facility oil piping category.

FACILITY OIL PIPING		
Year	**Number of Spills**	**Total Volume (gallons)**
1995	10	1,338
1996	22	1,668
1997	18	4,235
1998	25	4,202
1999	11	6,523
2000	15	2,333
2001	17	2,983
2002	16	7,756
2003	21	5,714
2004	19	3,227
2005	10	2,778
2006	14	1,873
2007	5	39,294
2008	23	159,642
2009	14	2,567
Grand Total	**240**	**246,132**

Table 3-12 presents the number and total volume of spills by spill size category. Figure 3-27 depicts the same data, which shows that a few large spills account for the vast majority of the total volume spilled. The three spills over 10,000 gallons are just 0.3% of the total number, but account for 79% of the total volume spilled. The 18 spills greater than 1,000 gallons represent 7.6% of the number of spills, but account for 90% of the total volume spilled.

Table 3-12. Number and total volume (gallons) of facility oil piping loss-of-integrity spills by size category.

Size Class	< 10	≥ 10 – < 100	≥ 100 – < 1,000	≥ 1,000 - < 10,000	≥ 10,000 - < 100,000	≥ 100,000	Total
Number	104	73	45	15	3	0	240
Percent	43.3%	30.4%	18.8%	6.3%	1.3%	0.0%	
Volume (gallons)	296	2,696	14,206	33,790	195,146	0	246,134
Percent	0.1%	1.1%	5.8%	13.7%	79.3%	0.0%	

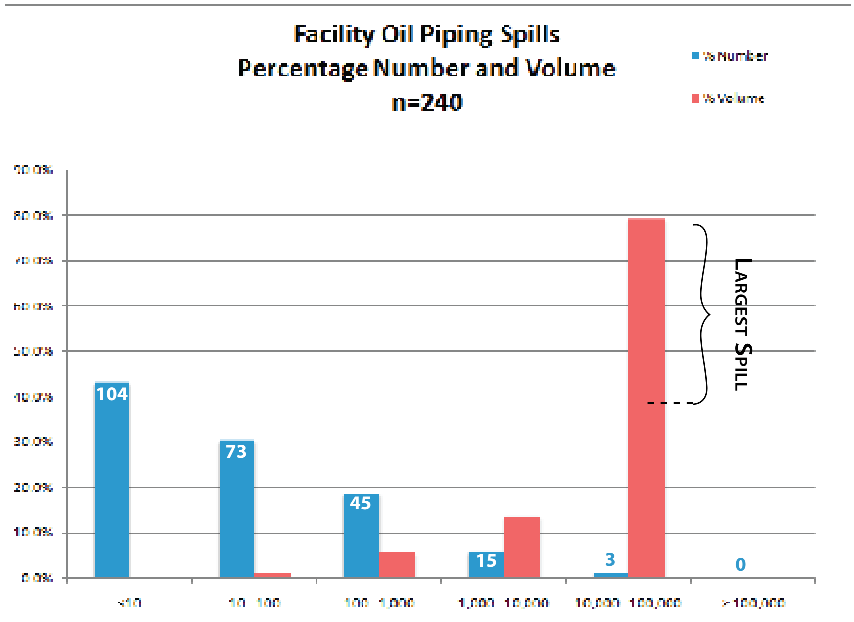


Figure 3-27. Percentage of number and total volume (gallons) of loss-of-integrity spills by size.

The facility oil piping category includes pipelines that run from individual wells to the manifold connected to a flowline as well as pipelines connected to above ground oil storage tanks. Thus for the purpose of this study, the facility oil piping category was divided into the following two sub-categories based on service: well lines and tank lines. Well lines accounted for 97% (232 cases) and tank lines accounted for only 3% (8 cases) of the facility oil piping spills. The average spill volume for well lines (1,066 gallons) was much larger than the average spill for tank lines (102 gallons).

Table 3-13 and Figure 3-28 present the primary cause breakdown of facility oil piping spills. Valve/seal failure was the greatest cause of spills (100), followed by operator error (34), internal corrosion (21), and thermal expansion (18). The single largest spill of 94,920 gallons was caused by internal corrosion.

Table 3-13. Primary cause of failure for facility oil piping spills.[8]

FACILITY OIL PIPING SPILLS n=197	
Primary Cause	**Number**
Valve/Seal Failure	100
Operator Error	34
Internal Corrosion	21
Thermal Expansion	18
Overpressure	9
Erosion	8
External Corrosion	3
Construction, Installation or Fabrication Related	3
Vibration (wind-induced/slugging)	1
3rd Party Action	1

8 Note that n is the number of spill cases. Some cases have more than one primary cause, so the number of cause assignment exceeds the number of cases.

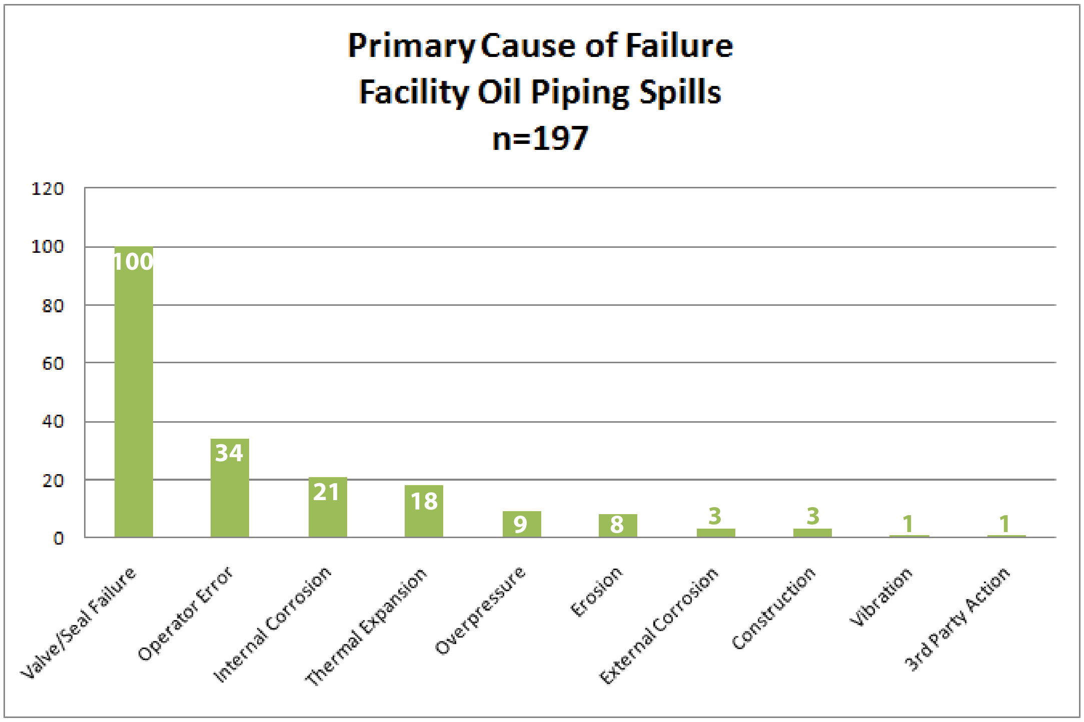


Figure 3-28. Primary cause of failure for facility oil piping spills.

Figure 3-9 (page 29) depicts the number of facility oil piping spills by year. Figure 3-29 depicts a bar graph of total spill volume by year with an overlaid scatter plot of actual spill events plotted over the same time period. Statistical analysis does not indicate a significant trend of the number of facility oil piping spills over time (Append H3.3).

Spills from facility oil piping occur at the highest frequency of any spill category and the spill severity has increased over the study period. The majority of facility oil piping leaks occur on well pads between the well and the flowline manifold and are caused by valve/seal failure.

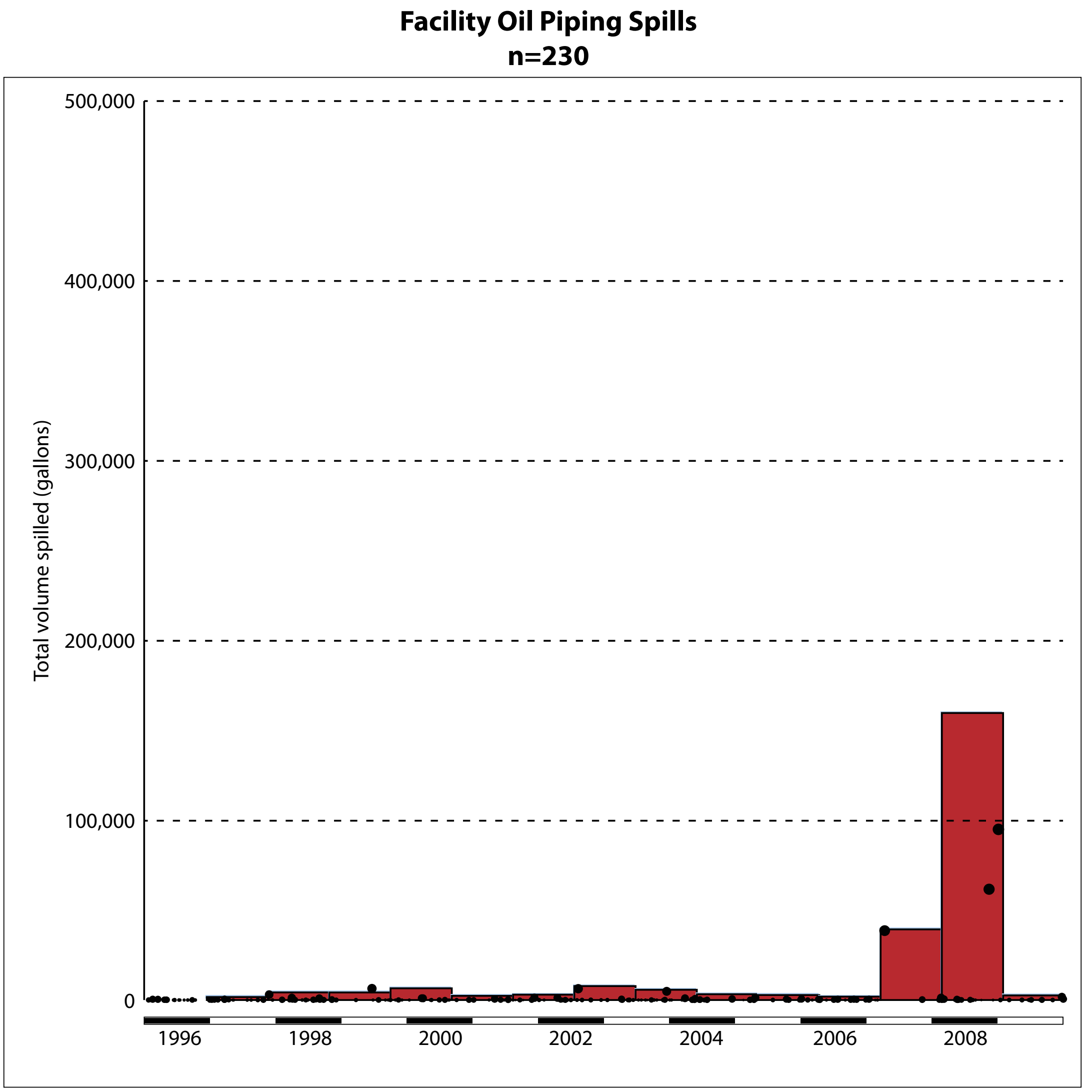


Figure 3-29. Bar graph of total spill volume (gallons) by year and scatter plot of actual spill events, all facility oil piping loss-of-integrity spills.

3.2.4 Process Piping

Table 3-5 (page 28) shows that the regulatory category with the second largest number of spill cases is process piping, with 202 spill cases. These spills represent 38% of the total loss-of-integrity spills. The volume spilled from process piping was 156,356 gallons or 13% of the total volume spilled across all spills in the study. Process piping exhibits the second highest spill frequency of 13.9 spills per year. Process piping is responsible for a large number of relatively small spills. Figure 3-30 maps the spatial distribution of process piping spills. Table 3-14 presents the annual number of spills and total volume for loss-of-integrity spills in the process piping category.

Table 3-14. Annual number of spills and total volume (gallons) for process piping loss-of-integrity spills.

PROCESS PIPING		
Year	Number of Spills	Total Volume (gallons)
1995	5	13,005
1996	16	13,742
1997	17	5,578
1998	15	4,176
1999	12	1,202
2000	13	8,656
2001	12	6,629
2002	12	12,415
2003	10	12,194
2004	11	33,300
2005	17	6,477
2006	21	7,261
2007	19	9,572
2008	15	2,545
2009	7	19,593
Grand Total	**202**	**156,345**

Table 3-15 presents the number and total volume of spills by spill size category. Figure 3-31 depicts the same data, which shows that a few large spills account for the vast majority of the total volume spilled. Two spills over 10,000 gallons make up only 1.0% of the total number of spills, but account for 79% of the total volume spilled. The 26 spills greater than 1,000 gallons represent 14% of the number of spills, but account for 93% of the total volume spilled. The number of spills is much more broadly distributed across the size classes than other categories.

Table 3-15. Number and total volume (gallons) of process piping spills by size category.

PROCESS PIPING							
Size Class	< 10	≥ 10 – < 100	≥ 100 – < 1,000	≥ 1,000 - < 10,000	≥ 10,000 - < 100,000	≥ 100,000	Total
Number	104	73	45	15	3	0	240
Percent	43.3%	30.4%	18.8%	6.3%	1.3%	0.0%	
Volume (gallons)	296	2,696	14,206	33,790	195,146	0	246,134
Percent	0.1%	1.1%	5.8%	13.7%	79.3%	0.0%	

The process piping category includes pipes inside flowline manifold buildings, inside modules at the processing centers, and seawater pipelines. Thus for the purpose of this study, the process piping category was divided into the following three sub-categories: well manifolds, processing center modules, and seawater pipelines. Table 3-16 presents the number and total volume for each of the process piping sub-categories. Process piping at processing centers accounted for 74.4% (148) of the cases. Process piping spills at processing centers are more frequent and severe than spills from well manifolds or sea water lines.

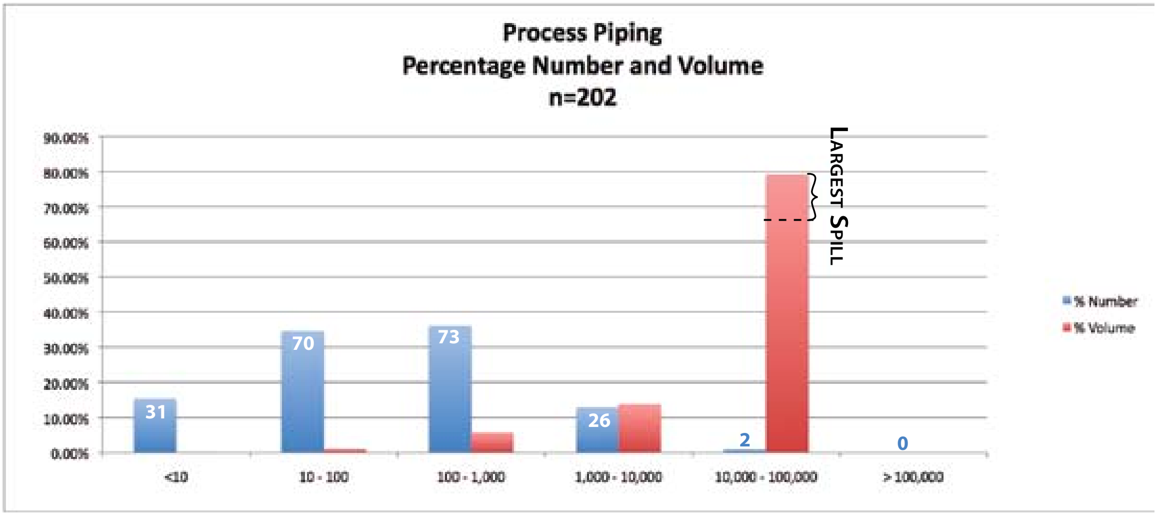


Figure 3-31. Number and total volume (gallons) of process piping spills by size category.

Table 3-16. Number and total volume (gallons) of process piping spills by process piping category.

PROCESS PIPING				
Sub-category	Well Manifold	Processing Centers	Sea water	Total
Number	7	148	44	199
Percent	3.5%	74.4%	22.1%	
Total Volume (gallons)	1,899	121,434	32,699	156,032
Percent	1.2%	77.8%	21.0%	

Table 3-17 and Figure 3-32 present the primary cause breakdown of process piping spills. Valve/seal failure was the greatest cause of spills (68), followed by operator error (34), internal corrosion (21), thermal expansion (11), and erosion (10). The two largest spills were caused by valve/seal failure and internal corrosion.

Table 3-17. Primary cause of failure for operational oil transmission pipeline spills.[9]

PROCESS PIPING SPILLS n=160	
Primary Cause	Number
Valve/Seal Failure	68
Operator Error	34
Internal Corrosion	21
Thermal Expansion	11
Erosion	10
External Corrosion	7
Overpressure	4
Construction, Installation or Fabrication Related	2
Vibration (wind-induced/slugging)	1
3rd Party Action	0

9 Note that n is the number of spill cases. Some cases have more than one primary cause, so the number of cause assignment exceeds the number of cases.

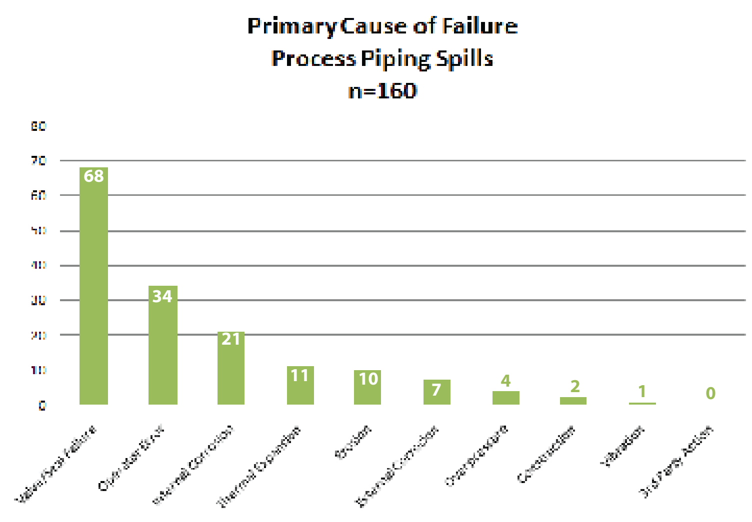


Figure 3-32. Primary cause of failure for process piping spills.

Figure 3-9 (page 29) presents the number of process piping spills by year. Figure 3-33 depicts a bar graph of total spill volume by year with an overlaid scatter plot of actual spill events plotted over the same time period. Statistical analysis does not indicate a significant trend of the number of process piping spills over time (Append H3.4).

Spills from process piping occur at the second highest frequency of any category and neither spill count nor average spill volume show any trend over the study period. Spills from this sub-category have a high frequency and a relatively low severity when they do occur.

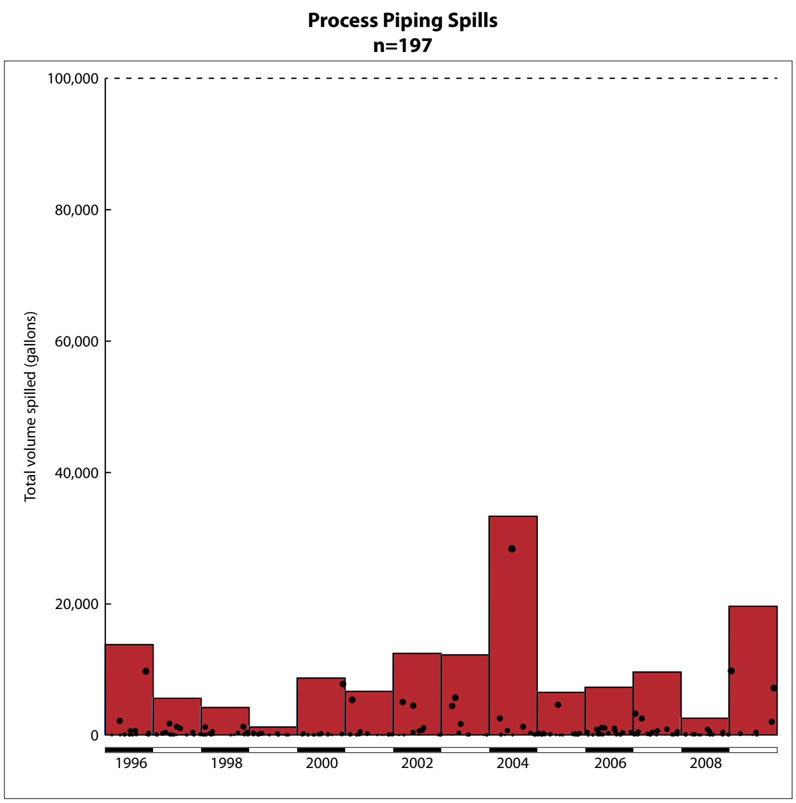


Figure 3-33. Bar graph of total spill volume (gallons) by year and scatter plot of actual spill events, all process piping loss-of-integrity spills.

3.2.5 Wells

Spills from the wells category are the result of leaks from the well head or the well casing during normal production operations. Table 3-5 (page 28) shows that the regulatory category with the third largest number of spill cases is wells, with 108 spill cases. The frequency of spills from wells is 7.4 spills per year. This represents 17% of the total number of loss-of-integrity spills. The volume spilled from wells was 66,638 gallons, representing just 6% of the total volume spilled across all spills in the study. The average volume of 617 gallons per spill is the lowest of all spill categories. Figure 3-34 maps the spatial distribution of wells spills. Table 3-18 presents the annual spill number and total volume for loss-of-integrity spills in the wells category.

Table 3-18. Annual number of spills and total volume (gallons) for loss-of-integrity spills in wells category.

WELLS		
Year	Number of Spills	Total Volume (gallons)
1995	2	25
1996	4	54
1997	3	765
1998	5	72
1999	3	14
2000	8	301
2001	6	36
2002	5	11,816
2003	11	232
2004	10	279
2005	11	51,576
2006	12	802
2007	8	27
2008	8	336
2009	12	304
Grand Total	**108**	**66,638**

Table 3-19 presents the percentage of number and total volume of spills by spill size category. Figure 3-35 depicts the same data, which shows that two large spills account for the vast majority of the total volume spilled. The two spills over 10,000 gallons represent only 2% of the total number of spills, but account for 79% of the total volume spilled. The 18 spills greater than 1,000 gallons represent 7.6% of the number of spills, but account for 94% of the total volume spilled. The majority of well spills are less than ten gallons.

Table 3-19. Number and total volume (gallons) of well spills by size category.

WELLS							
Size Class	< 10	≥ 10 – < 100	≥ 100 – < 1,000	≥ 1,000 - < 10,000	≥ 10,000 - < 100,000	≥ 100,000	Total
Number	58	36	12		2		108
Percent	53.7%	33.3%	11.1%	0.0%	1.9%	0.0%	
Volume (gallons)	193.50	872	2,763		62,809		66,638
Percent	0.3%	1.3%	4.2%	0.0%	94.3%	0.0%	

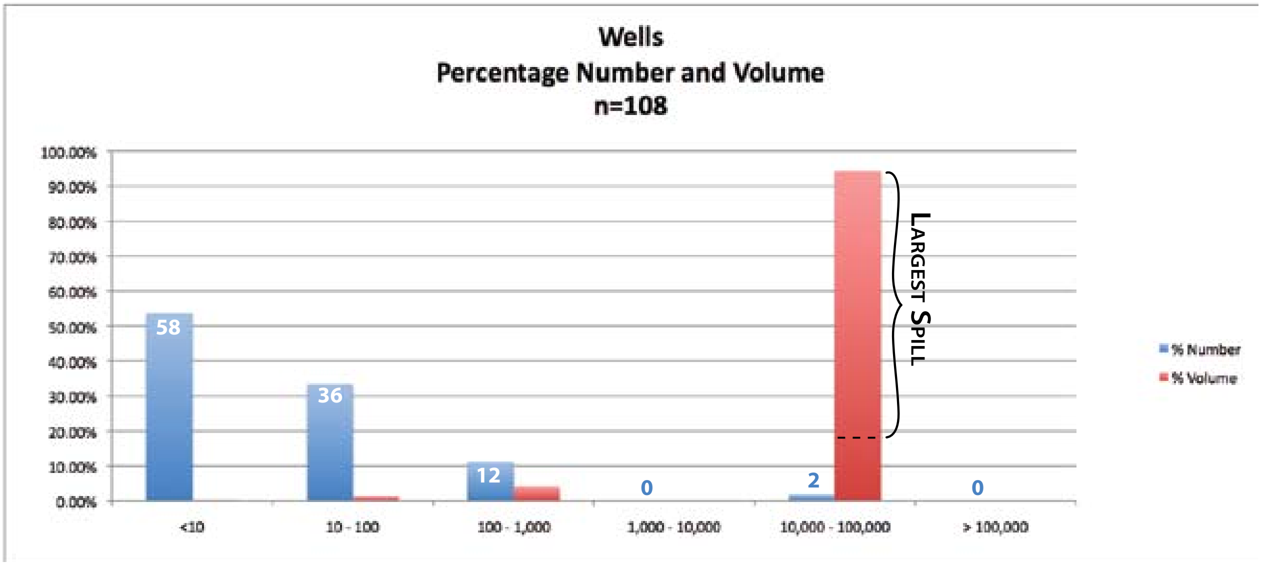


Figure 3-35. Number and total volume (gallons) of well spills by size category.

Table 3-20 and Figure 3-36 present the primary cause breakdown of well spills. Valve/seal failure was by far the greatest cause of spills (42), followed by over pressure (5), thermal expansion (4), operator error (4), internal corrosion (3) and construction installation or fabrication (3). The largest spill of 51,198 gallons was caused by internal corrosion.

Table 3-20. Primary causes of failure for well spills.[10]

WELL SPILLS n=62	
Primary Cause	**Number**
Valve/Seal Failure	42
Overpressure	5
Thermal Expansion	4
Operator Error	4
Internal Corrosion	3
Construction, Installation or Fabrication Related	3
Erosion	1
External Corrosion	0
Vibration (wind-induced/slugging)	0
3rd Party Action	0

Figure 3-9 (page 29) depicts the number of well loss-of-integrity spills by year. Figure 3-37 depicts a bar graph of total spill volume by year with an overlaid scatter plot of actual spill events plotted over the same time period. Statistical analysis indicates that there is a significant upward trend over time for spills from wells (Appendix H4.5).

Spills from this sub-category are occurring at a statistically significant increasing rate, though they have a low severity when they do occur. Spills in this category suggest that wells leaks are showing some characteristics that could be related to aging.

10 Note that n is the number of spill cases. Some cases have more than one primary cause, so the number of cause assignment exceeds the number of cases.

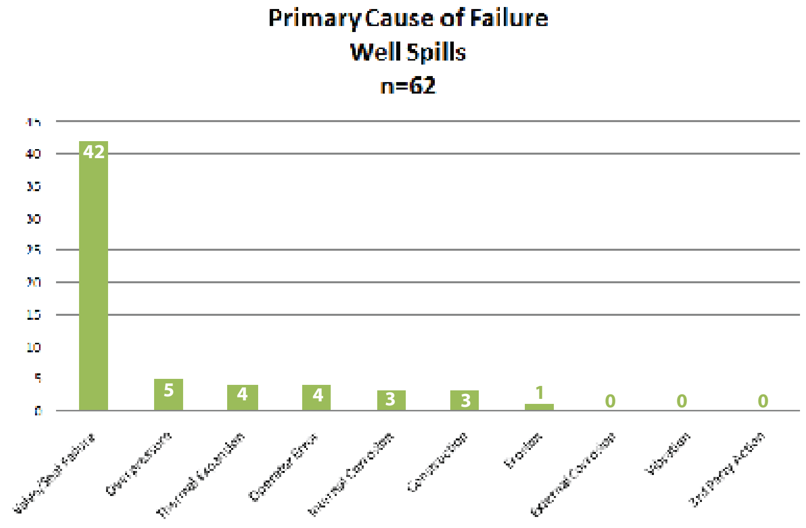


Figure 3-36. Primary cause of failure for well spills.

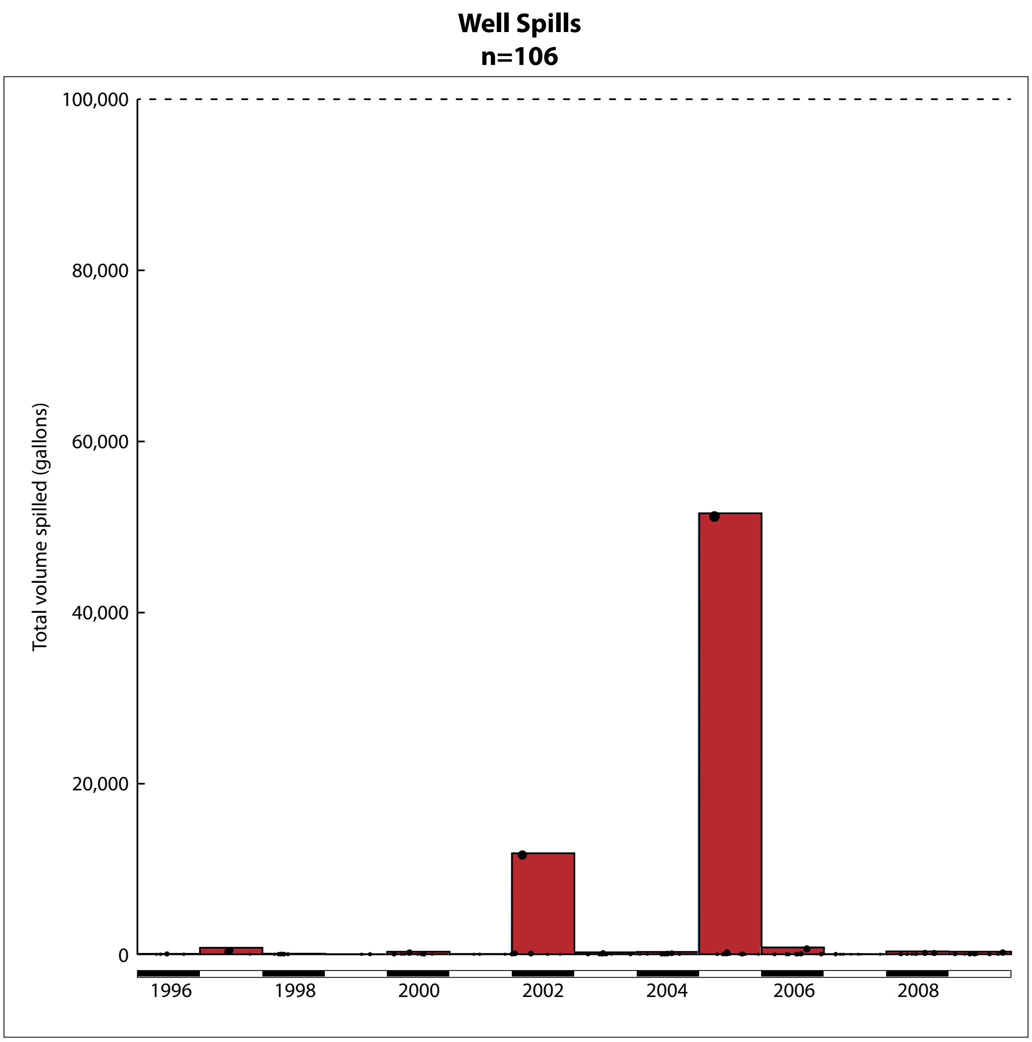


Figure 3-37. Bar graph of total spill volume (gallons) by year and scatter plot of actual spill events, all well loss-of-integrity spills.

3.2.6 Above Ground Oil Storage Tanks

The single largest spill during the study period (214,038 gallons) was from an above ground oil storage tank. Yet, Table 3-5 (page 28) shows that this regulatory category has the second lowest frequency of spills with 10 spill cases, an average of 0.7 spills per year. These 10 spills represent just 2% of the total number of loss-of-integrity spills. However, the total volume spilled from above ground oil storage tanks was 247,137 gallons, which is 21% of the total volume spilled across all spills in the study. Figure 3-38 maps the spatial distribution of above ground oil storage tank spills. Table 3-21 presents the annual spill number and total volume for loss-of-integrity spills in the above ground oil storage tanks category.

Table 3-21. Annual number of spills and total volume (gallons) for loss-of-integrity spills in above ground storage tanks category.

ABOVE GROUND OIL STORAGE TANK		
Year	**Number of Spills**	**Total Volume (gallons)**
1995	1	2
1996	0	0
1997	0	0
1998	2	3,370
1999	0	0
2000	0	0
2001	1	2,600
2002	3	104
2003	1	20
2004	0	0
2005	0	0
2006	1	241,038
2007	0	0
2008	0	0
2009	1	3
Grand Total	**10**	**247,137**

Table 3-22 presents the number and total volume of above ground oil storage tank spills by spill size category. Figure 3-39 depicts the same data, which shows that the single large spill in 2006 accounts for the vast majority (98%) of the total volume spilled.

Table 3-22. Number and total volume (gallons) of above ground oil storage tank spills by spill size category.

ABOVE GROUND OIL STORAGE TANKS							
Size Class	**< 10**	**≥ 10 – < 100**	**≥ 100 – < 1,000**	**≥ 1,000 - < 10,000**	**≥ 10,000 - < 100,000**	**≥ 100,000**	**Total**
Number	4	2	1	2		1	10
Percent	40.0%	20.0%	10.0%	20.0%	0.0%	10.0%	
Volume (gallons)	9	30	100	5,960		241,038	247,137
Percent	0.0%	0.01%	0.04%	2.4%	0.0%	97.5%	

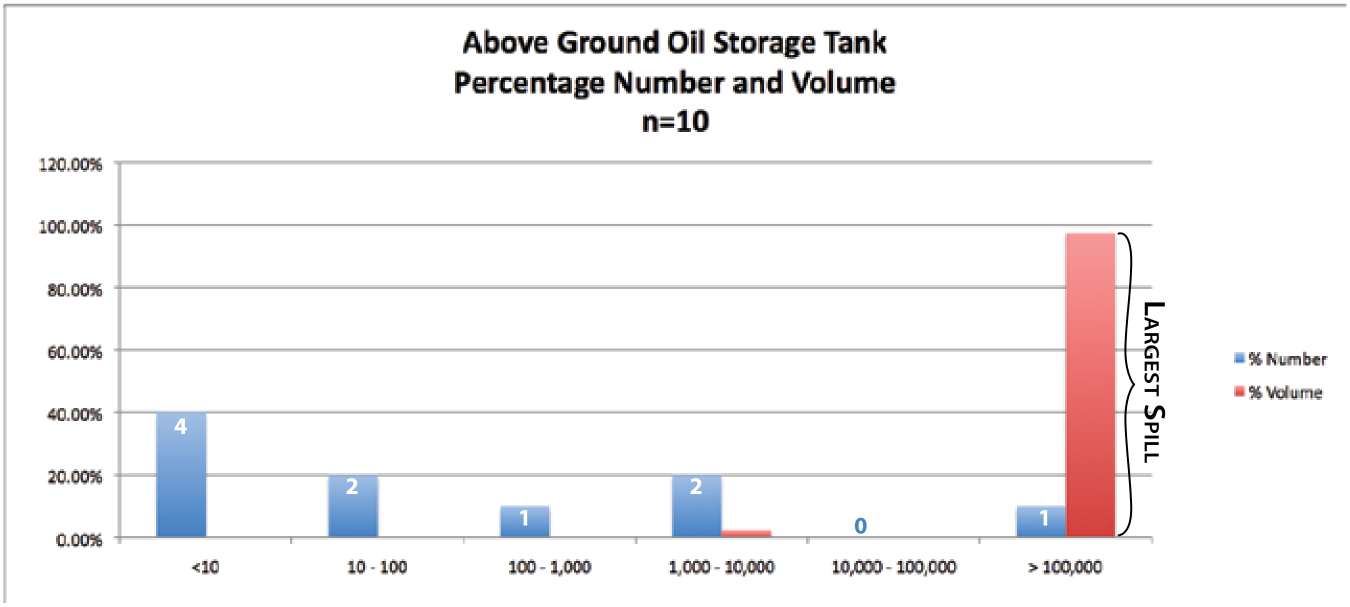


Figure 3-39. Number and total volume (gallons) of above ground oil storage tank spills by spill size category.

Table 3-23 and Figure 3-40 present the primary cause breakdown of above ground oil storage tank spills. Operator error was the greatest cause of spills. The largest spill of 241,038 gallons was caused by material failure.

Table 3-23. Primary cause of failure for above ground storage tank spills.[11]

ABOVE GROUND OIL STORAGE TANK SPILLS n=5	
Primary Cause	**Number**
Operator Error	3
External Corrosion	0
Internal Corrosion	0
Erosion	0
Thermal Expansion	0
Construction, Installation or Fabrication Related	0
Vibration (wind-induced/slugging)	0
Overpressure	0
Valve/Seal Failure	0
3rd Party Action	0

Figure 3-41 depicts a bar graph of total spill volume by year with an overlaid scatter plot of actual spill events plotted over the same time period. Graphical analysis reveals no trend in number or volume across the study period.

The single large spill in 2006 is a major contributor to the severity of spills, but the frequency and severity of all other spills from this category has been very low.

11 Note that n is the number of spill cases. Some cases have more than one primary cause, so the number of cause assignment exceeds the number of cases.

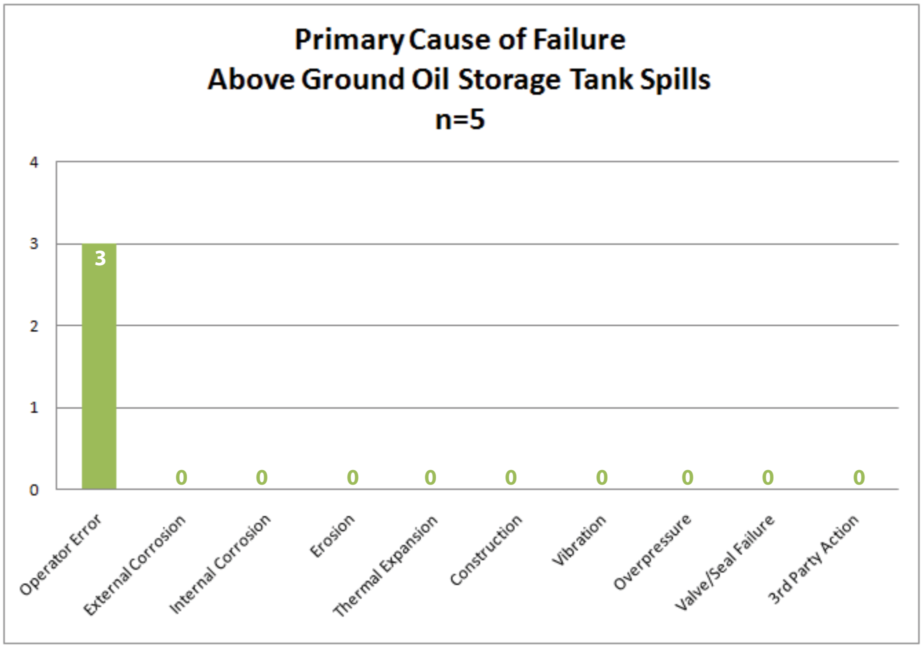


Figure 3-40. Primary cause of failure for above ground storage tank spills.

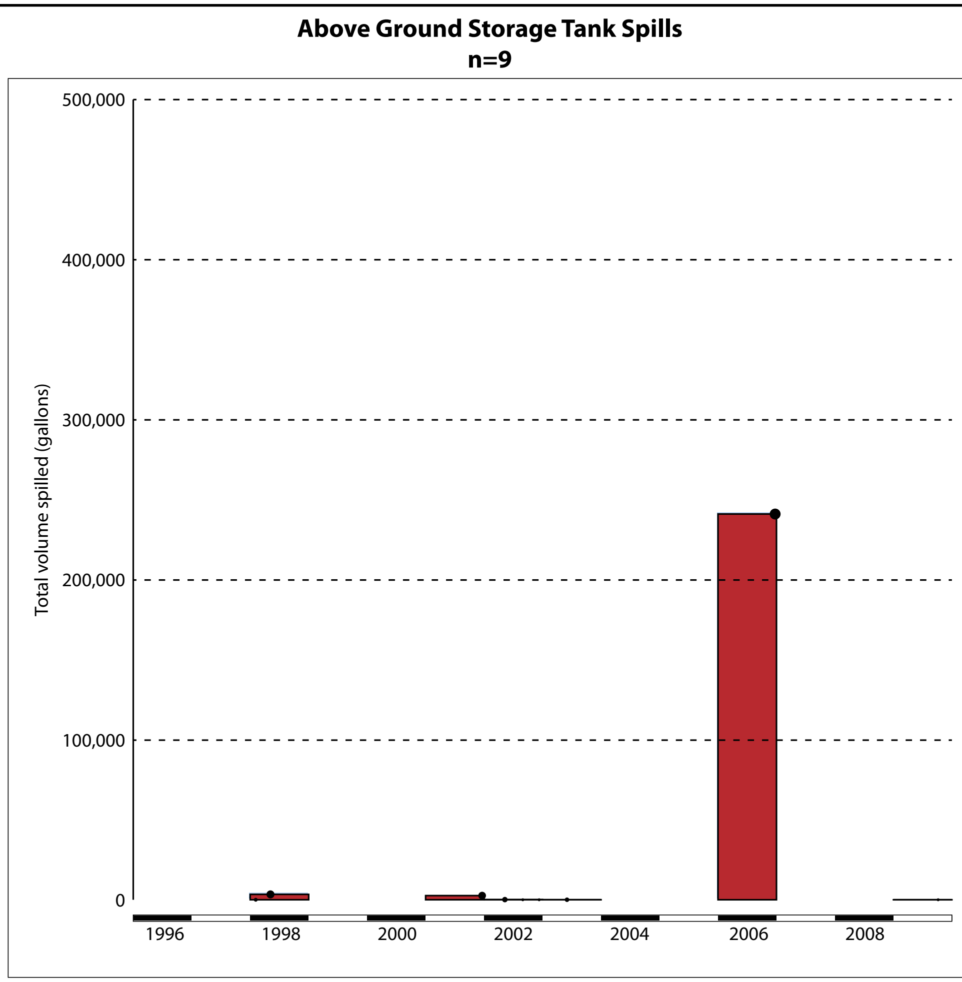


Figure 3-41. Bar graph of total spill volume (gallons) by year and scatter plot of actual spill events, all above ground storage tank loss-of-integrity spills.

3.2.7 Comparison Across Regulatory Categories

Figure 3-42 presents a binning of regulatory categories by the spill frequency and severity. The colors of the matrix are meant to indicate the relative risk of that cell. Colors are based on the best professional judgment of the authors. The severity scale is logarithmic, meaning each cell is ten times greater than the adjacent cell. Thus, moving one cell left or right represents a much greater change than moving one cell up or down. Each cell contains any relevant regulatory category followed by the number of spills in that category during the analysis time period. Facility oil piping, process piping, and well spills occur at the highest frequencies. All regulatory categories - oil transmission pipelines, above ground storage tanks, facility oil piping, flowlines, process piping, and wells have contributed spills that are in the top two severity categories.

FREQUENCY (Spills per Year)	Less than 10	10 to 100	100 to 1,000	1.000 to 10,000	10,000 to 100,000	Greater than 100,000
Greater than 5	FOP-104		PP-73			
4 to 5	W-58	FOP-73 PP-70				
3 to 4			FOP-45			
2 to 3	PP-31	W-36				
1 to 2		FL-18	FL-22	FOP-15 PP-26		
Less than 1	FL-14 OTP-5 AGST-4	OTP-2 AGST-2	AGST-1 W-12	FI-13 OTP-1 AGST-2	FOP-3 FL-4 PP-2 W-2	OTP-1 AGST-1

SEVERITY (gallons spilled)

KEY:
W = Wells
PP = Process Piping
FOP = Facility Oil Piping
FL = Flowline
OTP = Oil Transmission Pipeline
AGST = Above Ground Storage Tanks

Convention: Regulatory Category – Total spills during the study period.
FOP-45 is Facility Oil Piping 45 spills.

Figure 3-42. Matrix of frequency and severity of spills showing relative contribution of each regulatory category during the study period.

Figure 3-43 shows the linear trends in spill frequency over the study period. While not all these trends lines are statistically significant (Appendix H4), the graph illustrates that although the overall number of spills has remained essentially constant over time, decreases in the number of facility oil piping and flowline spills are being offset by an increase in the number of well spills.

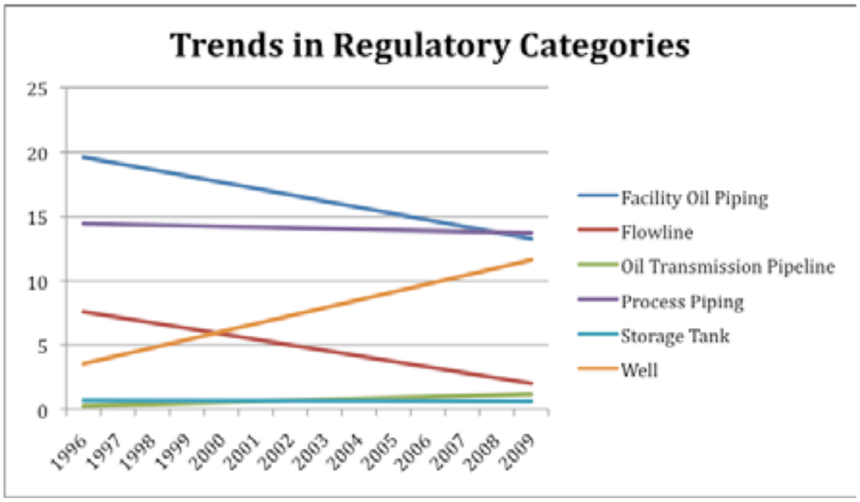


Figure 3-43. Spill trends expressed in number of spills for each regulatory category from 1996 to 2009.

Examination of these data reveals the following:

- Above ground storage tanks and oil transmission pipelines have a very low spill frequency, less than one per year. Each accounts for about 20% of the total volume spilled, but this is solely because of the two large spills in 2006.
- Total spill volume is uniformly distributed between storage tanks, oil transmission pipelines, flowlines and facility oil piping, with less total oil spilled from process piping and wells. However, the total volumes associated with storage tanks and oil transmission pipelines are the result of a single spill in each category.
- Facility oil piping, process piping, and wells all contribute the most to spill numbers, but contribute proportionately less to spill volume.
- The flowline category exhibits the highest percentage (31%) of large spills (≥ 10,000).

Measures for reducing spill frequency would be most effectively aimed at facility oil piping, process piping, and wells, while measures for reducing spill severity would be most effectively focused on flowlines.

3.3 Analysis of Spill Data by Primary Cause of Failure

Data on the primary cause of failure is of interest to examine common causes of failures that resulted in loss-of-integrity leaks. To understand the data it is important to understand the relationships between causes and how the data are coded into the NSS database. Causes are not mutually exclusive, so more than one cause can be assigned to a spill case. Causes can be interactive; corrosion may weaken a pipeline enough that wind induced vibration causes a material failure of the pipe or weld, which leads to a spill. Causes can be hierarchical, in that some causes are sub-sets of others. Internal Corrosion is a subset of Corrosion and in turn, Corrosion could be a subset of Material Failure of Pipe or Weld. The causes used for this study were assigned to standard cause categories developed after an initial review of the database, spill case files, and cause investigation methodologies. Cases were assigned to one or more primary causes based on information obtained from SPILLS database, case file, and the oil discharge prevention and contingency plan and interpreted based on the best professional judgment of the reviewer. Cases assigned to the flowline and oil transmission pipeline regulatory categories were reviewed by the operators to validate cause, since these spills were of particular interest.

The following illustrates the hierarchical relationship of the cause categories:

- Material Failure of Pipe or Weld
  - Corrosion
    - External Corrosion
    - Internal Corrosion
  - Erosion
    - External Erosion
    - Internal Erosion
  - Thermal Expansion
  - Construction, Installation or Fabrication Related
  - Original Manufacturing-Related
  - Vibration (wind-induced/slugging)
  - Overpressure
- Valve/Seal Failure
- Operator Error
- 3rd Party Action

Although material failure at pipe or weld was a common cause designation, occurring 123 times in the 640 spill records, the Expert Panel suggested that this cause designation be ignored because it is overly broad and duplicative of other causes.

Figure 3-44 presents a binning of selected primary causes of failure by the spill frequency and severity. The colors of the matrix are meant to indicate the relative risk of that cell. As stated before, colors are based on cause category assignments that reflect the best professional judgment of the authors and the severity scale is logarithmic, meaning each cell is ten times greater or lesser than the adjacent cell. Each cell contains any relevant primary cause followed by the number of spills in that category during the analysis time period. Valve/seal failures occur at the highest frequencies. Internal corrosion, external corrosion, valve/seal failure, and thermal expansion are primary causes of failure that occur in the top two severity categories.

Because more than one primary cause of failure can be assigned to a single case, statistical analysis required some simplifying assumptions (Appendix H3). However the following facts are apparent in the data:

- Valve/seal failure is the most frequent cause of all spills,
- Corrosion is the most frequent cause for spills greater than 1,000 gallons,
- Valve/seal failure is the most frequent cause for smaller spills,
- Spill severity is dependent on spill cause in some cases,
- Valve/seal failures account for an unusually high percentage of well spills,
- Operator error accounts for an unusually high percentage of storage tank spills,
- Corrosion accounts for an unusually high percentage of flowline spills,
- Corrosion is a larger problem for Kuparuk River than for Prudhoe Bay.

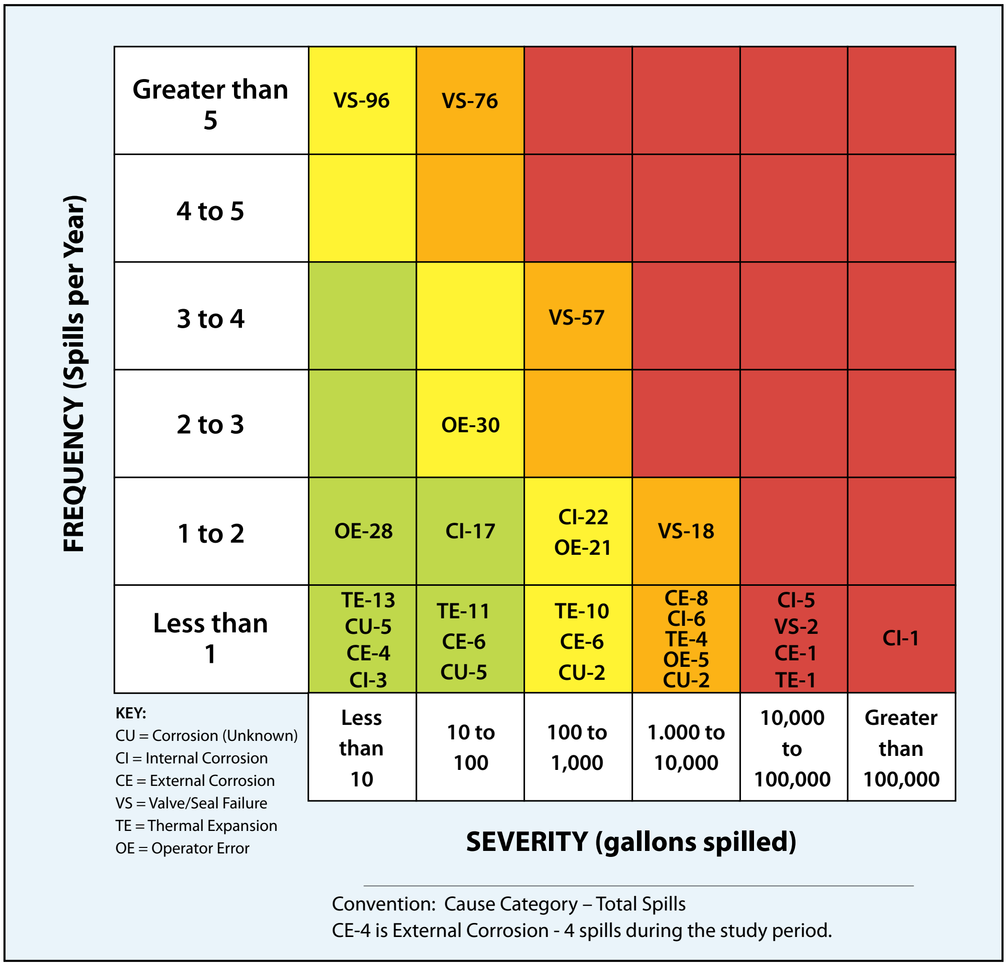


Figure 3-44. Matrix of frequency and severity of spills showing relative contribution of selected primary causes of failure during the study period.

3.4 Comparison of Leak Rates

Leak rates can be calculated by normalizing the number and/or volume of leaks by production throughput or by pipeline length for pipeline spills. Leak rates can be useful to compare one oil field with another, but these rates still have the underlying problems associated with the number and volume data. Volumetric leak rates based on amount spilled will still have the large variations caused by the few very large spills and numeric leak rates based on number of leaks are limited when there are very few spills from an oil field.

3.4.1 Leak Rates Based on Total Production

One way to analyze loss-of-integrity leak rates across the entire oil production infrastructure is to consider the production volumetric leak rate, which is the proportion of produced oil and water that ends up spilled. This is the ratio between the total amount of oil and produced water spilled at each oil field during the study period and the total amount of oil and water produced from that field, expressed as barrels per million barrels (bbl/mm bbl). This data, which includes spills across all six regulatory categories included in the study, are presented by oil field in Table 3-24 and Figure 3-45.

Table 3-24. Amount of oil and produced water spilled vs. oil and produced water throughput by oil field with corresponding volumetric leak rate.

Oil Field	Volume Oil Spilled (gallons)	Volume Produced Water Spilled (gallons)	Total Volume Oil & Water Spilled (gallons)	Volume of Oil Produced (gallons)	Volume of Produced Water Produced (gallons)	Total Oil & Water Produced (gallons)	Volumetric Leak Rate (bbl/mm bbl)	Largest Spill (gallons)
Badami	295.00	0	295.00	5,198,420	0	5,198,420	56.8	200
Colville River	5,071.70	168	5,239.70	351,632,828	30,977,761	382,610,589	13.7	4,998
Endicott	1740.00	4,921	6,661.00	169,210,549	963,111,138	1,132,321,687	5.9	4,410
Kuparuk River	356,898.10	16,122	37,3020.10	1,123,177,607	2,775,282,031	3,898,459,638	95.7	94,920
Milne Point	64,960.13	8,676	73,636.13	235,844,750	489,873,571	725,718,321	101.5	38,600
Northstar	98.00	0	98.00	141,811,174	28,679,622	170,490,796	0.6	84
Prudhoe Bay	464,365.07	277,475	74,1840.07	2,987,017,635	6,549,833,660	9,536,851,295	77.8	241,038
All Oil Fields	**893,428.00**	**307,362**	**1,200,790.00**	**5,013,892,963**	**10,837,757,783**	**15,851,650,746**	**75.8**	**241,038**

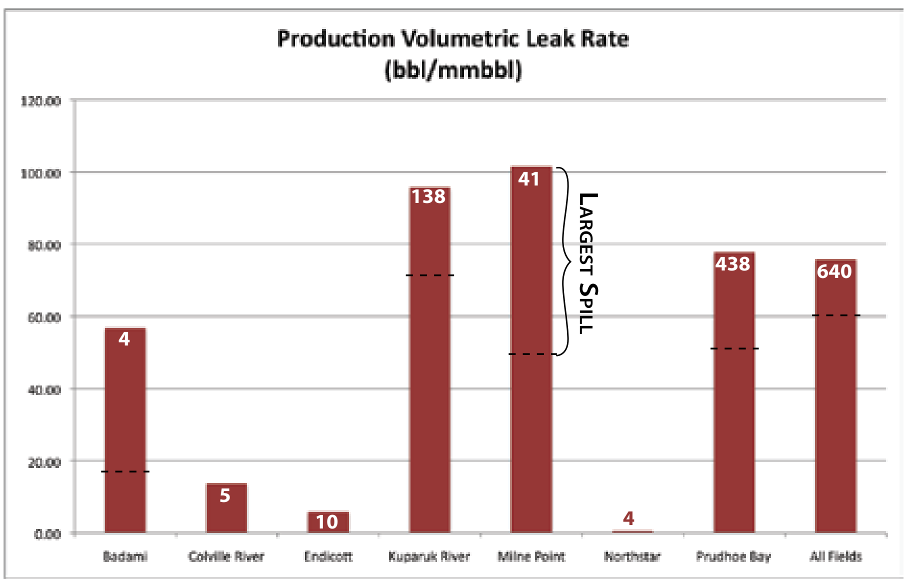


Figure 3-45. Production volumetric leak rate expressed as ratio of spilled volume to total volume (gallons) of oil and water produced, by oil field.

The production volumetric leak rate varies dramatically across North Slope oil fields. The combined leak rate for all oil fields on the North Slope was 75.8 bbl/mm bbl.[12]

This variability may not reflect actual systematic variations between the operations at these different fields. Since the largest spills account for a substantial portion of all the leak rate measurements, it is possible that fields like Endicott and Northstar, which have a proportionately lower leak rate, have had few of the high-volume spills that dominate the data. For example, if the Colville River - Alpine field

12 Another study of North Slope exploration and production oil spills calculated a different volumetric leak rate of 0.86 bbl/mm bbl of crude production from 1977 to 1999 (Maxim and Niebo 2001). This statistic is not directly comparable to the number calculated for this study, because the Maxim and Niebo study 1) included spills for sources other than loss-of-integrity and 2) their study considered the ratio of oil and produced water spilled to crude oil produced.

had not had one 5,000 gallon spill, its leak rate would be two orders of magnitude lower. Even for Kuparuk (138 spills) and Prudhoe Bay (438 spills), the largest spill is a substantial contribution to the total leak rate.

The production numeric leak rate is the ratio between the number of spills at each oil field during the study period and the total amount of oil and water produced from that field, expressed as spills per million barrels (spills/mm bbl). The numeric leak rate is presented by oil field in Table 3-25 and Figure 3-46 for all loss-of-integrity spills and those spills greater than 1,000 gallons. The production volumetric leak rate for all fields is 1.7 spills per million barrels of production and the rate for spills greater than 1,000 gallons is 0.2 spills/mm bbl. Note the large variation in oil fields where the number of spills are small.

Table 3-25. Numeric leak rate expressed as spills per million barrels for all North Slope loss-of-integrity spills and all North Slope loss-of-integrity spills greater than or equal to 1,000 gallons by oil field.

Oil Field	Number of Spills	Number of Spills ≥ 1,000	Total Oil and Water Production (bbls)	Leak Rate All Spills (spills/mm bbl)	Leak Rate for Spills ≥ 1,000 gallons (spills/mm bbl)
Badami	4	0	123,772	32.32	0.00
Colville River, Alpine	5	1	9,109,776	0.55	0.11
Endicott	10	2	26,960,040	0.37	0.07
Kuparuk River	138	21	92,820,468	1.49	0.23
Milne Point	41	8	17,279,008	2.37	0.46
Northstar	4	0	4,059,305	0.99	0.00
Prudhoe Bay	438	38	227,067,888	1.93	0.17
All fields	**640**	**70**	**377,420,256**	**1.70**	**0.19**

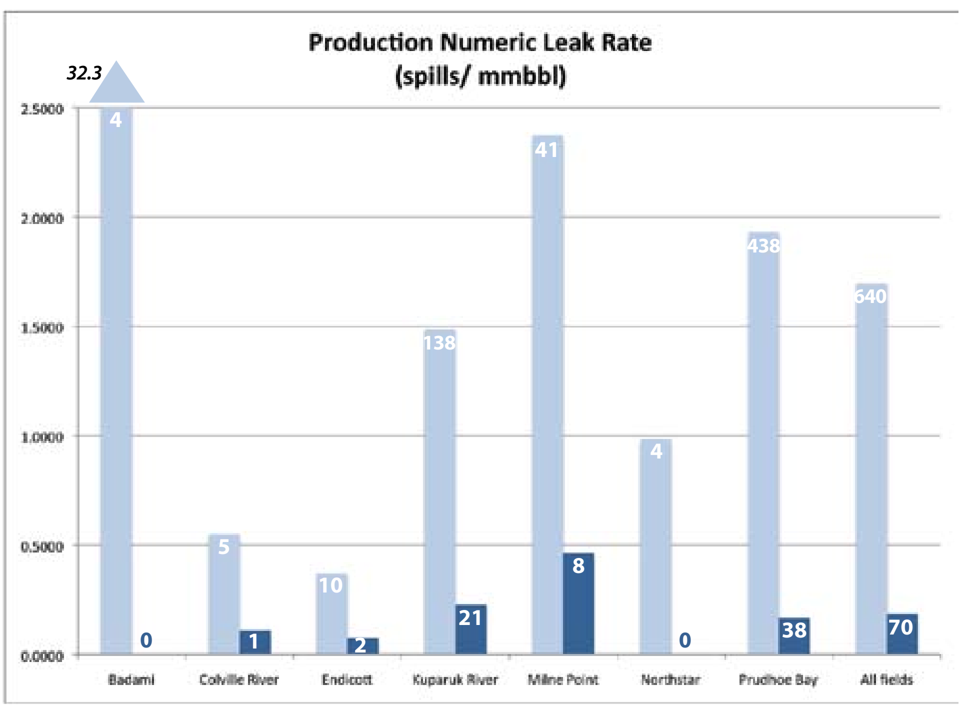


Figure 3-46. Production numeric leak rate expressed as spills per million barrels for all North Slope loss-of-integrity spills and all North Slope loss-of-integrity spills greater than or equal to 1,000 gallons.

Figures 3-47 and 3-48 depict plots of the production volumetric leak rate and production numeric leak rate (respectively) versus water to oil ratio for each oil field.[13]

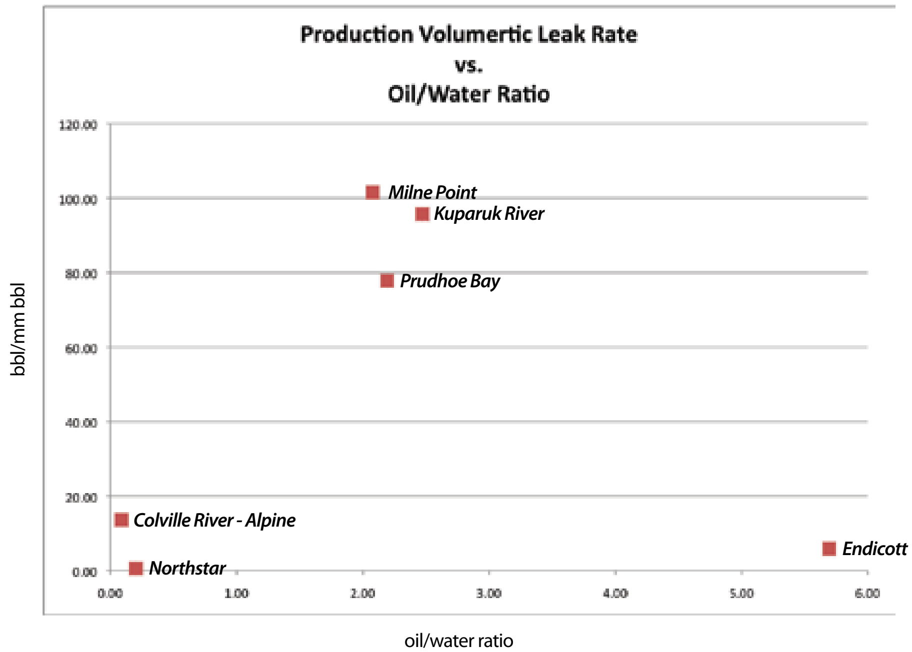


Figure 3-47. Production volumetric leak rate expressed as barrels per million barrels versus water to oil ratio by oil field.

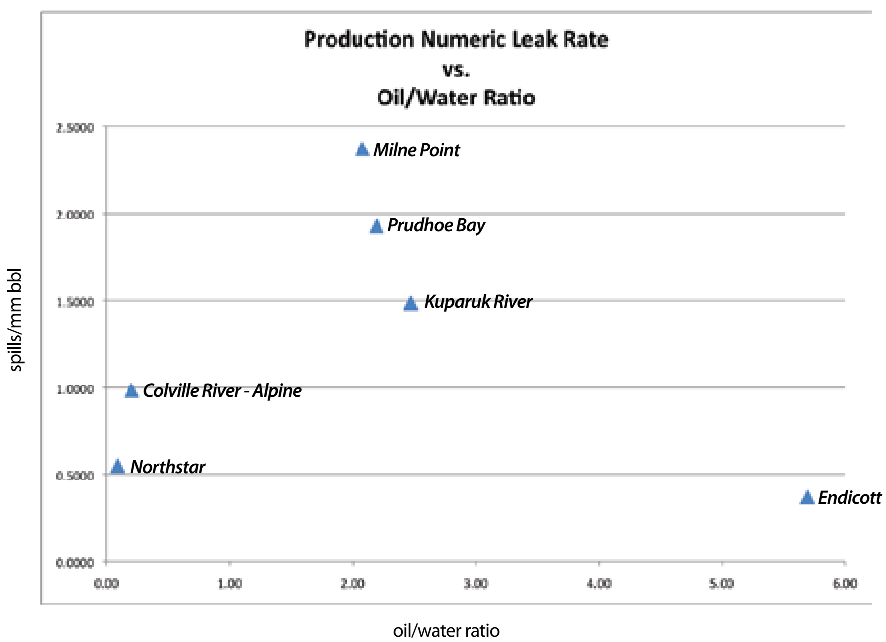


Figure 3-48. Production numeric leak rate expressed as spills per million barrels versus water to oil ratio by oil field.

Statistical analysis of production numeric leak rates did not show any trends over time during the study period, which corresponds to no trend in spill numbers. However, the statistical analysis did show significant differences between oil fields (Appendix H5.1).

13 The Badami oil field was excluded for these plots because of the erratic leaks rates associated with this field.

Graphical analysis of the production leak rates lead to the following observations:

- The Badami leak rates are extremely variable and should probably be disregarded due to the small number of loss-of-integrity spills from this field (n=4).
- The leak rates for the Colville River (n=5), Endicott (n=10), and Northstar (n=4) oil fields are based on small numbers of observations, but are consistently lower that the leak rates for Kuparuk River, Milne Point, and Prudhoe Bay. The Colville River (first production 2000) and Northstar (first production 2001) oil fields are much younger that the other fields and have lower water to oil ratios, which might offer an explanation for the lower leak rates.
- Endicott (first production 1986, 34 miles of pipelines) and Milne Point (first production 1985, 46 miles of pipeline) are roughly the same age and have similar pipeline lengths. However the leak rates for Milne Point are at least 6 times larger than the leak rates for Endicott. This comparison holds even when the largest spills are removed from the analysis.
- Kuparuk River and Prudhoe Bay are in a class by themselves in terms of age, production, pipeline mileage, number of spills, and volume of spills. Kuparuk River (95.7 bbl/mm bbl) has a higher volumetric leak rate than Prudhoe Bay (77.8 bbl/mm bbl). Prudhoe Bay (1.93 spills/ mm bbl, 0.17 spills/mm bbl) has a higher numeric leak rate for all spills and spills ≥ 1,000 gallons than Kuparuk River (1.49 spills/mm bbl, 0.23 spills/mm bbl). Overall Kuparuk River and Prudhoe Bay appear to be roughly equivalent in production leak rates.
- Plots of leak rate versus water to oil ratios show distinct groupings; Colville River – Alpine and Northstar have low water to oil ratios and low leak rates, Milne Point, Kuparuk River and Prudhoe Bay have higher water to oil ratios and higher leak rates, and Endicott has the highest water to oil ratio but a low leak rate.
- Endicott stands out as a field with a consistently low production leak rates.
- Excluding the erratic Badami oil field, Milne Point has the highest production leak rates of all other oil fields.

3.4.2 Leak Rates Based on Pipeline Length

For flowlines and oil transmission pipelines, mileage leak rates may also be considered based on pipeline length. The mileage volumetric leak rate is the amount of oil spilled per mile per year expressed as gallons per mile per year and the mileage numeric leak rate is the number of spills per mile per year. Table 3-26 contains the mileage volumetric and numeric leak rates for operational flowline and oil transmission pipeline spills for the Kuparuk River and Prudhoe Bay oil fields. There was insufficient data to calculate these rates for other fields.

Table 3-26. Gallons spilled per year per mile, by oil field and pipeline category.

Operational Spills	Oil Transmission Pipeline Volume per Year per Mile	Oil Transmission Pipeline Number per Year per Mile	n	Flowline Volume per Year per Mile	Flowline Number per Year per Mile	n
Kuparuk River	0.0056	0.0037	2	42.2396	0.0033	14
Prudhoe Bay	541.1818	0.0100	4	9.9818	0.0033	21

Figures 3-49 and 3-50 depict the mileage volumetric and numeric leak rates (respectively) for operational flowline and oil transmission pipeline spills for the Kuparuk River and Prudhoe Bay oil fields. As with production leak rates, Kuparuk flowlines (42.23 gallons/mile/year) had a higher volumetric rate than Prudhoe Bay flowlines (9.98 gallons per mile per year). The mileage numeric leak rates for Kuparuk River and Prudhoe Bay flowlines are identical (.0033 spills per mile per year). The Kuparuk River oil transmission pipeline (0.0056 gallons per mile per year) volumetric leak rate was very low compared to the Prudhoe Bay oil transmission pipeline (541.2 gallons per mile per year) leak rate, which was dominated by the single 2006 spill of 212,252 gallons. Excluding the 2006 spill, the Prudhoe Bay oil transmission pipeline leak rate would still have been 12.7 gallons per mile per year. The Prudhoe Bay oil transmission pipeline (40.8 spills per mile per year) numeric leak rate was four times higher than the Kuparuk oil transmission pipeline (0.0037 spills per mile per year) numeric leak rate.

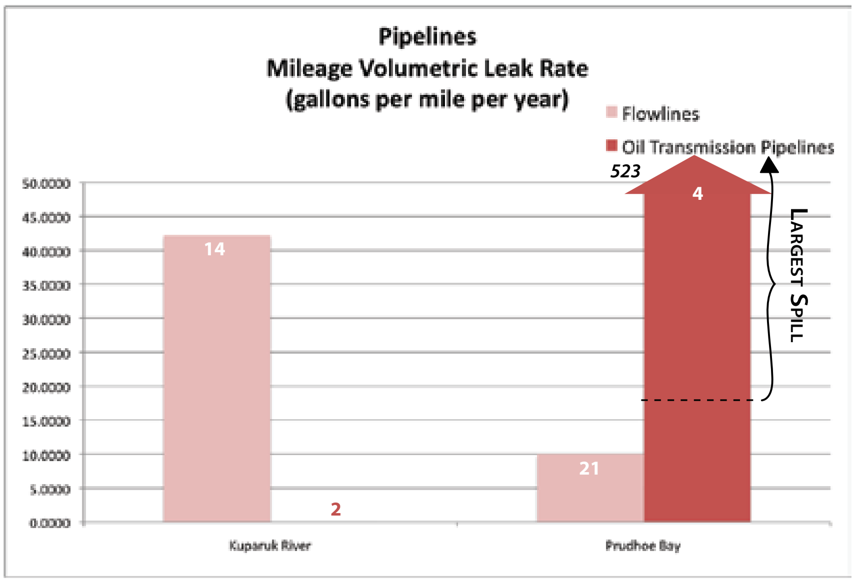


Figure 3-49. Mileage volumetric leak rate expressed as gallons per mile per year for operational flowline and oil transmission pipeline spills at Kuparuk River and Prudhoe Bay oil fields.

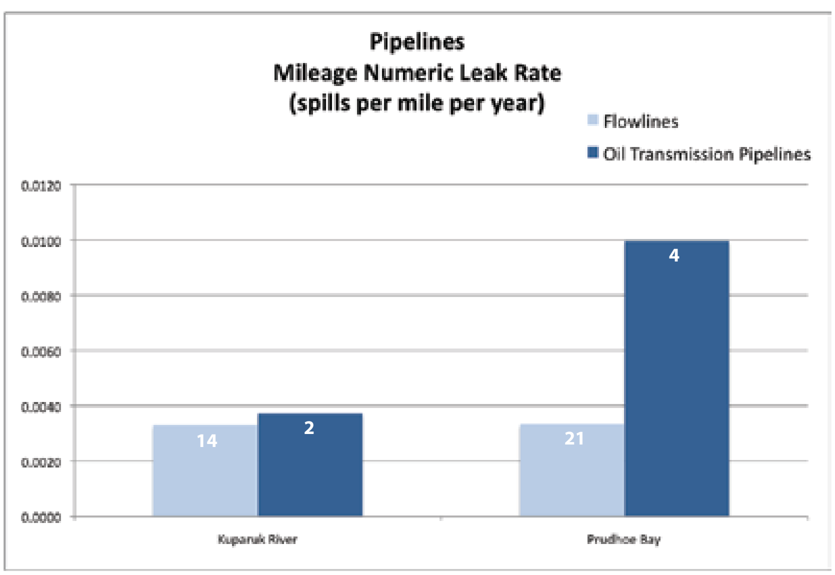


Figure 3-50. Mileage numeric leak rate expressed as spills per mile per year for operational flowline and oil transmission pipeline spills at Kuparuk River and Prudhoe Bay oil fields.

Interestingly, the Prudhoe Bay flowline and the Kuparuk flowline and oil transmission pipeline mileage numeric leak rates were all very similar, approximately 0.0035 spills per mile per year. These numeric leak rates are higher than in other studies which were typically less than 0.002 spills per mile per year. (Guevarra 2010, Anderson and Misund 1983, Hill and Catmur 1994, Lyons 2002).[14]

3.5 Analysis of Age at Failure

Age at failure is another metric that may be used to consider problems in a pipeline system. It might be hypothesized that older pipes fail more often than younger pipes. If this were the case, the frequency of failure would increase across an axis of pipeline age categories. The pipeline catalogue (Appendix C) contains 394 pipelines of which 44% have a known first date of service. The 44% is highly skewed to the Kuparuk River oil field where 99% of the pipelines have a known date of service. This provides a strong bias in the resulting analysis, but the results are still worth considering. Table 3-27 contains the years 175 pipelines were placed in service and the corresponding number of spills from each cohort. Figure 3-51 depicts the distribution of years the pipelines were placed in service.

Table 3-27. Number of pipelines placed in service by year and associated spills from those pipelines.

Year	Pipeline in Service	Number of Associated Spills
1977	2	1
1978	1	1
1979	3	2
1980	1	2
1981	3	1
1982	15	4
1983	12	6
1984	19	5
1985	34	7
1986	18	1
1987	11	1
1988	1	0
1989	4	0
1990	8	2
1991	1	0
1993	3	1
1994	6	2
1996	3	0
1997	1	0
1998	7	0
2000	1	1
2001	6	0
2003	2	0
2005	6	0
2006	2	1
2007	1	0
2008	3	0
2009	1	0
Grand Total	**175**	**38**

14 It should be noted that these studies are not based on 3-phase pipelines, but product and crude oil pipelines.

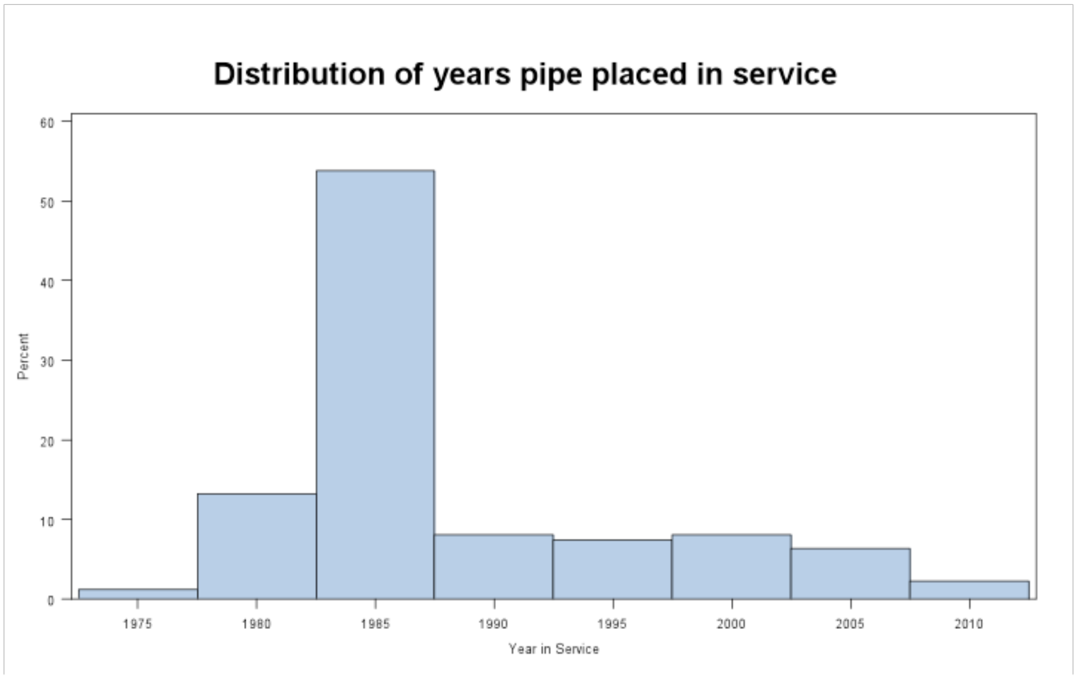


Figure 3-51. Distribution of year flowlines and oil transmission pipelines were placed in service.

It is evident that most of the piping was placed in service in the mid 1980s. The question arises as to whether or not the probability of a given pipeline failing is a function of time that it was placed in operation. A logistic regression model was designed to answer this question (Appendix H6).

The model proved to be significant; the odds that a pipeline will experience a spill increase by a factor of 1.109 for every additional year of service. For a pipeline that has been in service 5 years, the probability that it will experience a spill is 3.33%. Table 3-28 contains the probability of a spill for a pipeline as it ages. Additional regression analysis show that the probability of a spill occurring is highly correlated to pipeline length as would be expected (Appendix H6). This model indicated that, when controlling for age, each additional mile of piping increases the odds of having experienced a failure by a factor of 1.172 for every additional year of service.

Table 3-28. Prediction of probability of failure by pipeline age resulting from logistic regression model applied to North Slope pipeline and spill data.[15]

Years in Service	Probability of a spill (%)
5	3.33
10	5.45
15	8.80
20	13.91
25	21.30
30	31.18

While the analysis is limited by missing data it provides strong evidence that the probability of North Slope pipeline spills are positively correlated to the age and length of a pipeline.

15 The year-placed-in-service information in this data is biased to some oil fields because of missing data from other oil fields.

3.6 Analysis of Leak Detection

Figure 3-5 (page 25) demonstrates that a few large spills account for a large majority of the total volume spilled. Reducing the time to detect a leak could substantially reduce the severity of oil spilled on the North Slope from loss-of-integrity spills. This analysis is limited because the leak detection data collected for flowlines and oil transmission pipelines was substantially incomplete. The method of leak detection was determined for 48% of flowline and oil transmission pipe spill cases, but the time to leak detection was determined for only 8% of these case. Of the 38 cases where leak detection method was determined, 35 (92%) were detected visually, 2 (5%) were detected by odor, and 1 (3%) was detected both visually and by a leak detection system. Only 5 cases contain data on the amount of time that the leak occurred before it was detected. Of those, the average spill size for leaks detected in less than one day was 253 gallons and the average for leaks detected after more than one day was 108,646.[16] While the data is limited, it indicates that reducing the time-to-detection for spills on the North Slope could dramatically reduce the spill severity.

3.7 Analysis of Spill Impacts

To examine the environmental impacts for the flowline and oil transmission pipeline spills included in this study, five metrics were considered: total volume spilled, number of spills impacting tundra, total volume spilled to tundra, square footage of tundra impact, and number of spills that entered water. The timing of spills related to frozen conditions was also considered.

The most basic measure of environmental impact is the total volume spilled outside of containment, which was 484,541 gallons for flowlines and oil transmission pipelines during the study period. For spills that escape containment, the type of environment where the spill occurs has some correlation to its impact. For example, spills to gravel pads have a much less severe impact than spills to tundra. Table 3-29 presents the number, total volume, average volume, and square footage of impact to tundra. Tundra was impacted in 35% (28) of the 80 cases studied, with 78% of the total volume spilled (379,361 gallons) impacting the tundra. A total of 225,938 square feet or 5.2 acres were impacted by these spills. An average of 1.9 loss-of-integrity spills per year over the study period impacted tundra.

Table 3-29. Summary of spill impacts to tundra.

FLOWLINE AND OIL TRANSMISSION PIPELINE SPILLS			
	Number	Total volume (gallons)	Square Footage
Spilled on Tundra	28	379,361	225,938
Percentage	35.0%	78.3%	
Spilled on Gravel Pads	52	105,180	
Percentage	65.0%	21.7%	
Grand Total	**80**	**484,541**	

Spills to frozen tundra and snow generally have less impact than spills during the thawed period. Assuming that the tundra is frozen and at least partially covered with snow during the eight months from October 1st through May 31st, the spills impacting tundra were categorized into spills during the

16 These data are based on a very low sample size. N=5 for cases where the leak was detected in less than a day and n=2 for cases where the leak was detected after more than a day. One of the leaks in the was the largest spill in the flowline and oil transmission category.

frozen period and the thawed period. Table 3-30 presents the number, total volume, average volume, and square footage of spills that impacted tundra during the frozen and thawed periods. Thirty two percent (32%) of the spills occurred to frozen tundra, accounting for 82% of the volume spilled and 62% of the square footage impacted. Sixty eight (68%) percent of the spills occurred during the thawed period, accounting for 18% of the total volume spilled to tundra and 38% of the square footage impacted. Overall an average of 1.3 loss-of-integrity spills per year impacted a total of 1.9 acres of non-frozen tundra.

Table 3-30. Summary of spill impacts to frozen and thawed tundra.

FLOWLINE AND OIL TRANSMISSION PIPELINE SPILLS			
	Number	Total volume (gallons)	Square Footage
Frozen Tundra	9	311,447	140,078
Percentage	32.1%	82.1%	62.0%
Thawed Tundra	19	67,914	85,860
Percentage	67.9%	17.9%	38.0%
Grand Total	**28**	**379,361**	**225,938**

Table 3-31 shows that 28 loss-of-integrity spills (36%) impacted water bodies from flowlines and oil transmission pipelines during the study period. It could not be determined how much volume spilled into the water, because the percentage entering water is not recorded. However, data was collected about the proportion of the spills that impacted frozen water bodies versus non-frozen. Overall, 36% of the spills that impacted water bodies occurred during the non-frozen time of the year when the impact is likely most severe. This equates to 0.7 spills per year across the study period.

Table 3-31. Summary of spill impacts to water bodies.

FLOWLINE AND OIL TRANSMISSION PIPELINE SPILLS	
	Number
Frozen Water	18
Percentage	64.3%
Not Frozen Water	10
Percentage	35.7%
Grand Total	**28**

3.8 Other Analyses Performed

In addition to the analyses presented in this section, the authors also considered two other analyses for the North Slope spills: spills greater than 1,000 gallons since 1977 and pipeline diameter. However, these analyses showed no obvious trends, therefore they were not included in this report.

DISCUSSION 4

4.1 Significance of the Analysis

This analysis represents the first time that North Slope crude oil infrastructure has been systematically analyzed to look for trends and identify options for reducing the frequency and severity of future spills from this infrastructure. While the missing data impacted some of the analysis, overall the information gleaned by this review was sufficient to allow the Expert Panel convened to review this data to offer recommendations on measures to reduce the frequency and severity of future spills (See Section 5). The metrics used in this analysis establish benchmarks that may be used to judge future performance of the North Slope oil production infrastructure. The numeric leak rates establish the frequency of failure for this infrastructure, which will be useful for any quantitative risk assessment.

4.2 Overall Spill Trends

Six hundred and forty (640) loss-of-integrity spills were reported during the analysis time period from July 1, 1995 through December 31, 2009. An average of 44 loss-of-integrity spills occurred each year over the study period. There was no significant trend in the frequency of loss-of-integrity spills across all of the oil fields and regulatory categories from the North Slope oil and gas infrastructure.

The data on spill severity shows that a few large spills account for the vast majority of the total volume spilled from the North Slope oil production infrastructure. The two largest spills comprise 0.3% of the total number, but account for 38% of the total volume spilled. The 13 spills greater than 10,000 gallons represent 2% of the number of spills, yet account for 80% of the total volume spilled. The 70 spills greater than 1,000 gallons represent 11% of the number of spills, and account for 95% of the total volume spilled. Because of this non-normal distribution of the volume data, an average volume statistic does not represent either a typical or a probable spill and is therefore not useful to report.

There is some evidence that the frequency of large spills (≥ 1,000 gallons) trends upward over the study period. The two largest spills occurred in 2006 and 75% of the spills greater than 10,000 gallons occurred in the latter half of the study timeframe. Because of the non-normal nature of the volume data this trend of increasing severity cannot be deemed statistically significant.

4.3 Spill Trends by Regulatory Categories

Six regulatory categories of infrastructure were analyzed for this analysis.

4.3.1 Flowlines

Flowlines carry either 3-phase fluid or produced water between well pads and processing center. Most of the large diameter pipelines the North Slope are flowlines. This regulatory category accounts for about 11% of the number of spills and 22% of the total volume spilled. There were 71 flowline spills during the study period or 4.9 spill per year. The average spill volume for flowlines is twice the average of all spills. For this analysis, flowline spills were divided into two sub-categories: maintenance activity flowline spills (related to pigging) and operational flowline spills (not related to pigging). This data indicate that nearly half of the flowline spills are related to maintenance activities, and that these spills account for less than 10% of the total volume spilled.

Like most other categories, the total volume of operational flowline leaks is attributable to a few severe spills. External corrosion was the most common primary cause of failure leading to operational flowline spills. There was no significant trend in frequency or severity of operational flowline spills during the study period. Spills from this sub-category have a relatively low frequency, but a high severity when they do occur.

In contrast, both the frequency and severity of maintenance activity flowline spills show a significant downward trend over the analysis time period. Valve/seal failure was the leading primary cause of failure for this sub-category. Maintenance activity flowline spills have contributed little to the frequency or severity of spills during the past five years of the analysis time period.

4.3.2 Oil Transmission Pipelines

Oil transmission pipelines carry sales quality crude oil from production centers toward Pump Station One on the Trans-Alaska Pipeline. There were only 9 spills from oil transmission pipelines during the study period equating to 0.6 spills per year. Seven of those spills were less than 100 gallons, one was about 5,000 gallons, and one was the second largest spill across all categories (214,000 gallons). For the purpose of analysis, oil transmission pipelines spills were also divided into two sub-categories: operational spills and maintenance activity spills related to pigging

Although 71% percent of operational oil transmission pipeline leaks occurred in the last five years of the analysis time period, neither the frequency nor severity of transmission pipeline loss-of-integrity spills demonstrate a significant trend over the study time period.[1] Valve/seal failure was the most common cause of operational oil transmission pipeline spills, although the single largest spill in this sub-category (over 200,000 gallons) was caused by internal corrosion. The single large spill is a major contributor to the severity of spills, but the frequency of spills from this category has been very low.

Only two cases represent operational maintenance oil transmission pipeline spill cases associated with activities such as pigging. Maintenance activity oil transmission pipeline spills are not a significant contributor to either frequency or severity of loss-of-integrity spills on the North Slope.

4.3.3 Facility Oil Piping

The facility oil piping category includes pipelines that run from individual wells to the manifold connected to a flowline, and pipelines connected to above ground oil storage tanks. There were 240 facility oil piping spills during the study period, which equates to 16.6 spills per year, which is the highest spill frequency of any category. The volume spilled from facility oil piping was 20% of the total volume spilled across all spills in the analysis, making this category third in the total volume spilled. A few large facility oil piping spills account for the vast majority of the total volume spilled.

For the purpose of this analysis, the facility oil piping category was divided into two sub-categories

1 This lack of significant trend is due in part to the low number of spills.

based on service: well lines and tank lines. Well lines accounted for 96% of the facility oil piping spills. The average spill volume for well lines was much larger than the average spill for tank lines. The single largest spill from facility oil piping was caused by internal corrosion.

Spills from facility oil piping occur at the highest frequency of any category and severity of these spills has increased over the analysis time period. This category is showing some characteristics that could be related to aging.

4.3.4 Process Piping

Process piping is piping internal to buildings and modules and is not regulated by the ADEC. There were 202 process piping spills, equating to 13.9 spills per year, placing this regulatory category second in terms of spill frequency. The volume spilled from process piping was 13% of the total volume spilled across all spills. Like most other categories, a few large spills account for the vast majority of the total volume spilled; however, the number of process piping spills is more evenly distributed across the size cases than other categories.

For the purpose of this analysis, the process piping category was divided into the following three sub-categories based on service: well manifolds, processing center modules, and sea water piping. Processing center spills accounted for approximately three-quarters of all spill cases, and were both more frequent and severe than spills from well manifolds or sea water lines. The leading primary cause of failure was valve/seal failure. Neither spill frequency nor severity show any trend over the analysis time period. Spills from this sub-category have a high frequency and a relatively low severity when they do occur.

4.3.5 Wells

There were 108 spills from well equipment, equating to 7.4 spills per year, making wells the third largest in terms of number of spills. The volume spilled from wells was just 6% of the total volume spilled across all spills in the analysis, and the annual average volume per spill is the lowest of all regulatory categories. Two spills over 10,000 gallons account for nearly 80% of the total volume spilled.

The primary cause of well spills was valve/seal failure, followed by material failure, although the two largest spills were caused by internal corrosion and material failure respectively. Spills from wells occur at a moderate frequency compared to other categories, and the frequency of spills has increased significantly over the analysis time period, although the severity of these spills is comparatively low. This sub-category is showing some characteristics that could be related to aging.

4.3.6 Above Ground Storage Tanks

Only 10 spills occurred from above ground storage tanks, equating to 0.7 spills per year, making the category the second lowest in terms of number of spill cases. Above ground oil storage tanks, representing just 2% of the total number loss-of-integrity spills, however the volume spilled from above ground oil storage tanks accounted for 21% of the total volume spilled across all spills in the analysis. Almost all of the total volume spilled was from the single largest spill in the analysis.

The most prevalent primary cause of failure for above ground oil storage tanks spills is operator error, however the largest spill in this category was caused by material failure. Spills from above ground storage tanks occur at a low frequency, but can be severe.

4.4 Primary Cause of Failure

Analysis of the primary cause of failure shows that valve/seal failure is the most frequent cause of all spills, but corrosion is the most frequent cause of spills greater than 1,000 gallons. Primary cause of failure varies dependent on regulatory category. Corrosion is a dominant cause of failure for flowlines.

4.5 Leak Rates

Leak rates were calculated in two ways:

- Production leak rates - as a proportion of total throughput (spillage from all six regulatory categories as a function of total volume of oil and water produced), and
- Mileage leak rates - as a proportion of linear pipeline length (which applies only to oil transmission pipelines and flowlines).

In both instances numeric leak rates and volumetric leak rates were calculated. The data was broken out by oil field, for internal comparisons; it was also compared to reported leak rates from oil and gas production infrastructure in other regions.

The analysis shows that the production volumetric leak rate varies dramatically across North Slope oil fields, but that this variability may not reflect actual systematic variations between the operations at these different fields, but rather a skew to the data based on the dominance of a few large spills within the data set. Production numeric leak rates are more consistent. The Badami oil field leak rates are extremely variable and should probably be disregarded due to the small number of loss-of-integrity spills from this field. The leak rates for the Colville River – Alpine, Endicott, and Northstar oil fields are consistently lower than the leak rates for Kuparuk River, Milne Point, and Prudhoe Bay. Endicott and Milne Point are roughly the same age and have similar pipeline lengths, however the leak rates for Milne Point are at least 6 times larger than the leak rates for Endicott. Kuparuk River and Prudhoe Bay are in a class by themselves in terms of age, production, pipeline mileage, number of spills, and volume of spills. Kuparuk River has a slightly higher volumetric leak rate than Prudhoe Bay and Prudhoe Bay has a slightly higher numeric leak rate for all spills and spills ≥ 1,000 gallons than Kuparuk River. Overall Kuparuk River and Prudhoe Bay appear to be roughly equivalent in production leak rates. Endicott stands out as a field with consistently low production leak rates. Excluding the erratic Badami oil field, Milne Point has the highest production leak rates of all other oil fields.

The production leak rates for all oil fields combined were:

75.8 barrels spilled for every million barrels produced,

1.7 spills for every million barrels produced, and

0.18 spill greater than 1,000 gallons per million barrels of production.

There were no significant trends over time for production leak rates.

Mileage leak rates were calculated for flowline and oil transmission pipeline categories for the Prudhoe Bay and Kuparuk River fields. As with other volume metrics, the mileage volumetric leak rates were highly influenced by a few large spills. Sparse oil transmission pipeline spill data reduces the confidence in the rates calculated for this category. As with production leak rates, Kuparuk River and Prudhoe Bay flowlines performed roughly equally at 0.003 spills per mile per year.

4.6 Age at Failure

One component of this analysis was to determine whether the frequency and severity of spills reported from North Slope oil and gas operations had a relationship to the age of the infrastructure. If the oil and gas production infrastructure is deteriorating due to age, an upward trend in the number and average size of spills might be expected.

The data for age at failure has many missing values and is not consistent across oil fields. But for those pipelines that had leaks where the age of failure was determined, there is a significant correlation between the probability of a spill and the age of the pipeline. A logistics regression model predicts that a pipeline with 5 years of service has a 3.3% probability of having a spill and a pipeline with 30 years of service has a 31% probability of having a spill. This analysis provides evidence that spill probability is correlated to pipeline age.

4.7 Leak Detection

Analysis of both the time required to detect leaks and the detection methods used is limited because of missing data. However the limited data seems to support the hypothesis that reducing the time-to-detection for spills on the North Slope could dramatically reduce the spill severity. Almost all spills are detected visually, no spills were detected solely by a leak detection system.

4.8 Spill Impacts

Limited data were available to assess the types of environments impacted by North Slope spills in the data set. Where impact data was available, nearly 80% of the total volume spilled, impacted tundra, with approximately two-thirds of those tundra spills impacting thawed tundra.[2] Insufficient data was available to detect trends in spill impacts.

2 Thawed tundra is generally considered to be more environmentally sensitive than frozen tundra.

EXPERT PANEL RECOMMENDATIONS 5

This section summarizes the recommendations formed by the Expert Panel during their June 2-4, 2010 meeting. The Panel formed seven key recommendations for activities or interventions that may help the State of Alaska to achieve the goal of reducing the frequency and severity of oil spills from North Slope crude oil transmission pipelines and flowlines. For each recommendation, the Expert Panel identified the intended audience (generally, either regulators or operators), justification for how the recommendation will help the State to move toward the goal of reducing the frequency and severity of spillage, a discussion of key considerations, and examples of the types of activities or programs that may be used to implement the recommendation. The recommendations relate specifically and exclusively to the analysis of North Slope pipeline spill causal data discussed in Section 3 of this report. Please note that the recommendations have been numbered based on priority. The list progresses from activities that the Expert Panel believes would be most proactive to those that are more reactive.

1. Move to an integrated Integrity Management Program (IMP) that focuses on leading indicators.
2. Adopt or model IMP components at State level for flowlines and require documentation of IMP-like activities for flowlines.
3. Utilize existing and emerging technologies to reduce the time required to detect pipeline leaks.
4. Standardize and improve spill data collection in order to better assess trends and common causes of spills so that prevention measures can be targeted and evaluated to reduce future leaks.
5. Conduct regular and ongoing proactive risk analyses to maintain systems at a prescribed level of safety, and share information from risk analyses among operators and with regulators.
6. Oversee implementation of corrective or preventive measures to evaluate their impact and effectiveness.
7. Establish a system of escalated enforcement to enhance and increase regulatory attention on operators that have spills on the North Slope.

5.1 Focus Integrity Management on Leading Indicators

Recommendation

The Expert Panel recommends:

Move to an integrated Integrity Management Program that focuses on leading indicators.

This recommendation is targeted at North Slope crude oil infrastructure operators with oversight from regulators.

Justification

In order to reduce spills, which represent a low probability/high consequence event, operators and regulators must focus on reducing the lower-consequence incidents and near misses that lead up to spills.

Discussion

Modern safety management programs in many US industries, including crude oil production, are based upon the "pyramid" principle, which holds that for every one major event (injury, failure, oil spill), there are nearly 30 minor events and 300 near miss incidents. The implication of this theory, commonly referred to as the Heinrich safety pyramid (Heinrich 1931), is that interventions that prevent the near miss and minor incidents at the bottom of the pyramid will stop the chain of events that could lead up to the one major or catastrophic event. Figure 5-1 shows an example of a Heinrich safety pyramid.

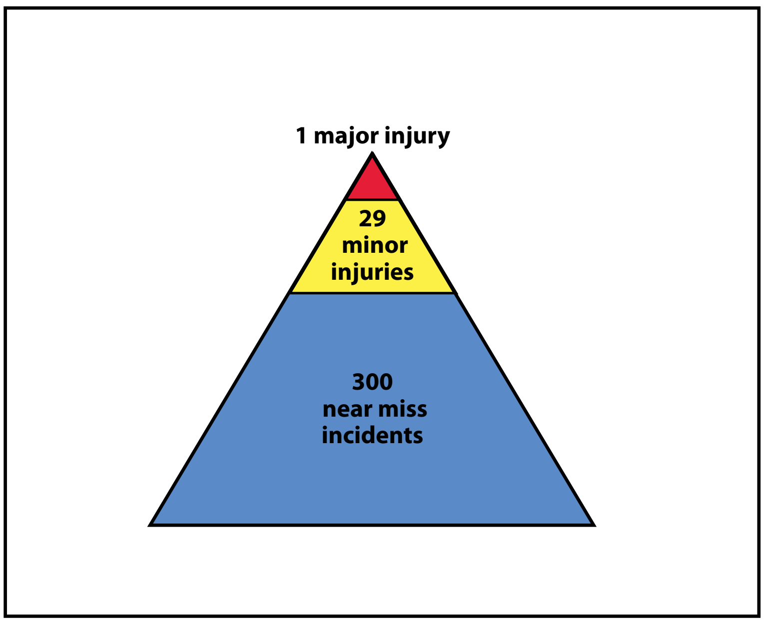


Figure 5-1. Heinrich Safety Pyramid.

The Expert Panel observed that the North Slope operators and regulators are focused on spills, which align with the top of the Heinrich Pyramid with regard to oil spill prevention. While the ultimate goal of both the regulators and the industry is to reduce the number of spills, current loss prevention philosophies suggest that focusing solely on spill prevention will not provide an acceptable reduction in the number of spills. A more effective means of spill prevention would be to focus on controlling the events that make up the base of the pyramid or the leading indicators of damage. By focusing on the precursor events that create the environment that results in an oil spill or pipeline leak, the damage mechanism is interrupted long before there is a threat to the integrity of the system. The key to this approach is to understand and identify the leading indicators preceding the failure modes that contribute to loss-of-integrity. Many modern safety management programs apply this approach of tracking leading indicators to prevent loss.

The challenge to this approach is that it requires an understanding and identification of the contributing causes to an event. Unlike the *proximate* or immediate cause, which is typically the precursor event that immediately precedes a spill, the *root cause* is the underlying problem or failure that led up to the incident (Gregory, Holly, and Thomas 1997). For example, for a pipeline leak caused by external corrosion, the *proximate* cause of the spill would be external corrosion of the pipeline. This tells us "what happened," but it doesn't explain "why." Contributing or root cause analysis provides an opportunity to investigate the underlying reasons for the leak – why the corrosion occurred. For this example, the root cause of the spill may have been wet insulation that allowed the corrosion process to take root. Water trapped between the outside insulation and the pipeline caused the pipeline to corrode and eventually fail. Recommendation #4 and Appendix F discuss various methodologies for conducting root cause analyses.

Once the root cause of a particular failure mode is understood (here, the link between wet insulation and external corrosion), operators and regulators can use that information to monitor for these types of spill precursors – also called "leading indicators" – as part of a prevention program. A program that effectively identifies and remedies wet insulation before it has the opportunity to externally corrode the pipe will stop the chain of events potentially leading up to an oil spill. Essentially, this intervention catches the problem while it is still in the lower part of the pyramid, before it can lead to a top of the pyramid type event (leak or spill).

The Expert Panel cited the U.S. Nuclear Regulatory Commission (NRC) risk-informed regulatory process as one example of utilizing leading indicators to manage risk.[1] This program also illustrates the escalated enforcement concept discussed under Recommendation #7. The NRC requires supplemental inspections for operators that have had occurrences of minor safety incidents above a certain level, in an attempt to catch accident precursors at the bottom of the pyramid, before they escalate into major events. The NRC program requires operators to cover the costs associated with these enhanced inspections.

The concept of leading indicators relates back to some of the discussion under Recommendation #4, regarding the value of near miss data. If the operators were to investigate the "saves" described in their corrosion reporting, as well as other near miss incidents, they may uncover additional insight into leading indicators. Such investigations may be occurring, but regulators of North Slope crude oil operators have limited access to this information. If regulators could have better access to this information and thus better understanding of the key leading indicators for pipeline leaks or failures, they may be able to establish more effective regulatory standards or tailor inspection practices toward these activities. The Panel agreed that better information about leading indicators could be used to set thresholds for prevention and inspection. Information from leading indicators would also feed into the proactive risk analyses discussed under Recommendation #5.

The Expert Panel agreed that the State must focus on failures that occur toward the base of the pyramid to reduce the number of spills and leaks at the top of the pyramid. They noted that the North Slope Spills Analysis was focused on the top-of-the-pyramid events: spills and leaks. However, their mitigation recommendations as summarized in this report are more comprehensive.

Implementation

The Expert Panel identified several possible mechanisms for implementing the recommendation to move to an integrated integrity management program that focuses on leading indicators. Further consideration of the analysis and recommendations in this report may lead to identification of additional implementation mechanisms.

The panel developed two examples of how integrity management programs could be structured to focus on leading indicators:

- **Corrosion Under Insulation (CUI)**
    - Move to aggressively monitor and control leading indicators of CUI, which is caused

1 More information on this NRC program is available at http://www.nrc.gov/about-nrc/regulatory/risk-informed/history.html

by moisture under insulation. Set targets for maximum occurrences of moisture under insulation. Yearly goals should focus on the expected declining trend of found moisture as a function of programs/processes/maintenance activities put in place to minimize or eliminate the presence of moisture under insulation.

- **Maintenance**
  - Adjust the timing of preventive maintenance activities to assure components never degrade past the point of their intended operating tolerances. A performance measure could be described, as "During normal preventive maintenance, no component will have an as-found condition below the intended operating tolerances." This is to move away from the process of waiting until a component fails.

5.2 Require Integrity Management Activities for Flowlines

Recommendation

The Expert Panel recommends:

> *Adopt or model Integrity Management Program (IMP) components at the State level for flowlines and require documentation of IMP activities for flowlines.*

This recommendation is targeted at regulatory agencies.

Justification

Integrity Management Programs (IMP) are a federal requirement for common carrier pipelines, under DOT regulations.[2] These requirements have been in place for several years and are well understood by the North Slope operators, since some of their pipelines are subject to the IMP requirements. North Slope flowlines are not subject to IMP requirements, although the operators report that many of the IMP elements are being applied to flowlines. By extending the requirement for IMP activities and documentation to flowlines, regulators will have greater access to reporting and documentation regarding flowline integrity. Since many of these practices are already in place unofficially, this requirement should not create undue hardship on the operators. Implementation could provide a number of benefits including better asset management, uniform reporting, increased regulator and public sector confidence, and reduced in-depth review and assessment of program adequacy.

Discussion

Expert Panel members discussed the federal IMP requirements at length. The role of pipeline integrity management is to identify the major threats to pipeline system integrity and then plan and implement inspection and maintenance and corrective action programs designed to evaluate and correct any potential problems that could lead to a loss-of-integrity. While the federal program has many benefits, one of the most important is that the inspection/audit process provides an opportunity for regulators to check on an operator's internal programs and processes to evaluate pipeline integrity and take corrective actions. Integrity management is designed essentially to prevent loss-of-integrity from a pipeline system over its entire service life. IMP interventions should target those elements of the system that become more vulnerable to failure over the life of the infrastructure, and enact additional barriers to failure.

A comprehensive pipeline integrity management program would incorporate many of the elements

2 49 CFR 195.450

discussed in the Expert Panel recommendations, such as:

- Targeting prevention measures to address common causes of past leaks (Recommendation #4);
- Oversight of corrective actions and preventive measures (Recommendation #6);
- Ongoing risk assessment (Recommendation #5); and
- Focusing on leading indicators (Recommendation #1).

Like many of the other recommendations brought forth by the Expert Panel, the integrity management process requires ongoing feedback and evaluation both by operators and by regulators. Once developed, integrity management programs must be continually evaluated to ensure they are having the intended results, and to modify them if needed. Assumptions that underlie IMP activities must be continuously validated with field data.

On the North Slope and within many other pipeline systems, the primary focus of integrity management has been on corrosion. There is a strong emphasis on corrosion control in the North Slope Charter agreement, and in the annual corrosion-reporting requirement under that agreement. The IMP requirements incorporate corrosion but also emphasize other aspects of pipeline operation, maintenance, and monitoring. The data presented in this North Slope Spills Analysis certainly supports the idea that corrosion is not the only failure mode associated with North Slope Spills. Corrosion only played a role in 30% (24) of the 80 flowline and oil transmission pipeline spills identified in this analysis. Therefore, a more comprehensive IMP would attempt to reduce spills caused by other modes of failure, and would extend the IMP requirements beyond crude oil transmission pipelines to also include flowlines.

The benefit of applying the IMP requirements to flowlines is that, from an implementation standpoint, there are already processes and procedures in place for oil transmission pipelines. Operators report they are currently proactively applying many facets of IMP to flowlines, so they should be able to expand these programs using existing policies and procedures. Regulators will then have access to substantially more information about infrastructure integrity. The challenge in this process is that the current oversight and regulation of these programs is done at the federal level; implementation by the State may require additional resources and expertise.

Implementation

The Expert Panel identified several possible mechanisms for implementing the recommendation to require IMP activities for flowlines. Further consideration of the analysis and recommendations in this report may lead to identification of additional implementation mechanisms.

- Apply the knowledge and programs/procedures developed for the DOT IMP to implement parallel requirements for North Slope flowlines.
- Focus efforts to minimize and eliminate spills on leading indicators of integrity degradation.
- Assess the adequacy of the operator's programs and monitor implementation effectiveness.
- Assure continuous improvement that uses captured data.
- Assure the use of good root cause analysis in both proactive and reactive assessment.

5.3 Reduce Leak Detection Times

Recommendation

The Expert Panel recommends:

> *Utilize existing and emerging technologies to reduce the time required to detect pipeline leaks.*

This recommendation is targeted at North Slope crude oil infrastructure operators with oversight from regulators.

Justification

Several of the large volume spills on the North Slope remained undetected for an extended period of time. Earlier detection would have proportionally reduced the spill volume. This recommendation will help the State to achieve the goal of reducing the severity of oil spills from North Slope oil transmission pipelines and flow lines by improving early detection of leaks to reduce product loss and damage to the environment.

Discussion

The Expert Panel and the Technical Support Team discussed leak detection technologies, effectiveness, and limitations during their June 2010 meetings. In reviewing the preliminary data analysis, the Expert Panel sought insight into whether lag times in leak detection had contributed to the severity of the larger spills in the data set. Figure 3-4 and Table 3-2 demonstrates that 11% of the spill cases account for 95% of the total volume spilled. While data on leak detection methods and timing for the spills considered in this analysis was limited (see Section 3.5), it appears to support the hypothesis that reducing the time-to-detection for spills on the North Slope could dramatically reduce the spill severity.

Where the spill is a result of a rapid outflow such as in a burst or guillotine break, better leak detection may not make a big difference in total volume release.[3] But, many of the largest spills are results of a low outflow from small holes that went undetected for an extended period of time. In these cases, improved leak detection will reduce the severity and environmental impacts of the spill.

Members of both the Expert Panel and the Technical Support Team discussed anecdotal cases that support the idea that improving leak detection capabilities might lead to a reduction in spill sizes and ultimately reduce the environmental damage from North Slope oil transmission and flowline loss-of-integrity spills.

During the Technical Support Team discussion, it was noted that to date, only a single North Slope oil transmission pipeline or flowline leak had been detected by leak detection systems; every other spill to date had been detected by a person, either through visual or olfactory observation. The North Slope operators confirmed that their most reliable leak detection technology, based on past results, seems to be operational personnel making firsthand observations, either by driving or walking by a spill location and seeing or smelling oil.

The Expert Panel and the Technical Support Team also agreed that leak detection sensitivity and the time lag between when a leak begins and when it is detected could be significant contributors to the overall size of the spill. Small spills that go undetected for an extended period of time have the potential to become large spills.

3 During the June 4, 2010 Expert Panel meeting one operator estimated that 20% to 30% of the pipeline leaks were "burst" types with a rapid outflow.

There seemed to be agreement among the Expert Panel, regulators, and operators that human detection was thus far the most effective, proven technology for leak detection. Yet, there are a number of engineering solutions to leak detection and these solutions have been examined for use on the North Slope. State oil spill contingency plans currently require a Best Available Technology (BAT) review for leak detection, and during a 2004 BAT conference sponsored by the State, several leak detection methodologies were considered for crude oil pipelines. The findings from that conference note that four of the methodologies represented variations on computational pipeline monitoring (CPM) systems, and one was an optical-based remote sensing system that detects leaks without performing computation on field parameters for inferring a spill. ADEC found that all of the CPM systems were found to meet the general criteria for BAT for leak detection from crude oil pipelines, and that the remote sensing system would provide a good supplemental capability to CPM (ADEC 2006).

The Expert Panel suggested that if BAT is not sufficiently developed to ensure credible leak detection, operating companies should pursue research and advance development of cutting edge technologies to bring such technologies to market. Researchers at Montana State University utilized the application of enhanced radiosonde technologies as a means to develop functional remote spill detection systems. Radiosonde technologies are generally associated with weather or atmospheric monitoring. However, the technology is adaptable to leak detection with relative ease. Microcontrollers were adapted to improve communication range and linked with peripheral sensing devices to identify and report the presence of hydrocarbon vapors. Such a system is self-healing, adaptable and has very limited power requirements. These are the types of technologies that the operating companies should be advancing to ensure rapid and dependable identification of pipeline leaks.

The Expert Panel agreed that until more reliable leak detection technologies are developed or applied to North Slope crude oil transmission pipeline and flowline leak detection, operators should be required to enhance their leak detection activities using the one proven method: human inspection. The Panel also recommended that improved data collection and root cause analysis into leak detection methods and time lags will help to inform further on how to reduce the time required to detect pipeline leaks and thus reduce the spill volumes caused by loss-of-integrity.

Implementation

The Expert Panel identified several possible mechanisms for implementing the recommendation to reduce the time required to detect pipeline leaks. Further consideration of the analysis and recommendations in this report may lead to identification of additional implementation mechanisms.

- Increase human inspection – visual and olfactory monitoring – where practicable.
- Conduct additional research and testing to identify new or existing state-of-the-art technologies that could improve leak detection sensitivity for North Slope crude oil transmission pipelines and flowlines.
- Investigate available remote sensing technologies, particularly for vapor/gas releases.
- Investigate use of cutting edge technologies such as distributed sensor linked microcontrollers to identify, locate and report leaks.
- Incorporate leak detection information (detection method and time required to detect) into spill data collection and spill investigations.

5.4 Improve Data Collection

Recommendation

The Expert Panel recommends:

> *Standardize and improve spill data collection in order to better assess trends and common causes of spills so that prevention measures can be targeted and evaluated to reduce future leaks.*

This recommendation is targeted at North Slope crude oil infrastructure operators with oversight from regulators.

Justification

This recommendation will help the State achieve the goal of reducing the frequency and severity of oil spills from North Slope oil transmission pipelines and flowlines by improving the quality and quantity of data collected regarding loss-of-integrity spill causes and trends in spill occurrence rates related to root and contributing causes, pipeline characteristics, operations and maintenance procedures, leak detection methods, geographic location, and impact area. By compiling data that will allow for analysis of these trends over time, space, and pipeline parameters, regulators and operators may be able to develop more effective prevention and mitigation measures. Eventually, spill data trends may be used to evaluate the effectiveness of these interventions. In order to effectively manage the spill risks from North Slope infrastructure, the State must effectively measure those risks, and an improved database with better causal information is essential to oversight and management of risks.

Discussion

The North Slope Spills Analysis focused on data from past spills to draw recommendations for future prevention and mitigation measures. The Expert Panel discussion focused heavily on the issue of data-driven decision-making. The Panel discussed the difference between *data* and *information*, and concurred that it is *information* that drives decisions. The challenge at hand is to compile and analyze data on North Slope pipeline leaks in a manner that is more informative to operators, regulators, and policy-makers and will help them to determine appropriate interventions or changes to improve the safety and integrity of that system.

The Expert Panel was presented with an early analysis of the data set described and discussed in Sections 2 and 3 of this report. The preliminary data set, which was compiled from the ADEC SPILLS database, was then sorted to include only loss-of-integrity spills from North Slope oil transmission pipelines and flowlines. The data was supplemented with all publicly available information regarding spill causes, detection methods, impacts, and corrective actions taken.

Expert Panel review and discussion of the North Slope Spill data set led to the observation that the quality of information available within the data set was insufficient to support the level of analysis desired. Many data fields were incomplete, and there was a notable lack of causal data, particularly root cause data. The data completeness matrix in Figure 2-2 shows that the North Slope Spill data was less than 50% complete for half of the data categories (meaning there was incomplete or missing data in 14 of the 28 categories examined). Areas where available data was particularly limited or incomplete were:

- identification of pipeline segment where leak originated,
- leak detection method used to detect spill,

- root/contributing causes,
- maximum allowable operating pressure for line that leaked,
- latitude/longitude of spill location,
- date of last pigging,
- frequency of pigging,
- pigged prior to incident,
- type of pigging,
- throughput of line that leaked,
- how long pipe was leaking prior to detection,
- in-depth investigation (operator, agency, or joint operator/agency) into leak,
- measurement of wall loss at time of spill, and
- production field to which the pipeline was linked.

Ironically, the areas where the data was most sparse coincided with many of the types of data that the Expert Panel identified as most important in order to develop recommendations for mitigation measures that target common causes of past spills. They emphasized that data collection should be driven by analytic parameters that facilitate future analyses of trends in causality and will also provide some baseline to gauge whether ongoing inspection or prevention measures can be correlated to a reduction in loss-of-integrity spills.

The Expert Panel noted that before establishing increased reporting and data management requirements, the rationale for collecting information should be clearly defined. Data reporting and collection processes should be driven by *how* the information is going to be used and analyzed, and whether that data will provide information useful to operational oversight. The Panel concurred that the types of information of highest interest to them, from the perspective of tailoring mitigation and prevention programs to those areas with the highest historical risk, were the following:

- Pipeline identifiers: specific location/type of pipeline, fluids carried, operating temperatures, velocities.
- Failure internal or external, proximity to radial welds, radial location, insulation type.
- Pipeline inspection/maintenance history: date of most recent inspection and results; coatings; repairs history; pigging profiles.
- Specific causes, linked to final causal analyses; root and contributing causes if identified. Do not permit “other” and minimize use of “unknown” to those cases where spill cause truly cannot be determined.

Appendix B contains blank and completed examples of the data collection form that was used in the North Slope Spills Analysis to populate the database discussed in Sections 2 and 3 of this report. The Expert Panel members recommended that, for all spills from North Slope oil transmission pipelines and flowlines, all the information fields in this form be included in an enhanced version of the ADEC database, with the addition of the following fields:

- Date of last inspection
- Description of inspection activity
- Inspection frequency
- Flow rate
- Leak rate – burst vs. slow leak

The Panel also recommended that operators be required to perform root cause analysis on all spills over a threshold volume (1,000 gallons was suggested). Although the Panel recommended using a threshold spill size to trigger root cause analysis, they noted that any time you limit a data set based on spill size, you may screen out important information about the chain of events that led up to the spill, and particularly the barriers that may have come into play to prevent a small leak from becoming a larger spill.

The Panel discussed the value of "near miss" data, and noted that investigative information about spills that *do not occur* can provide just as much insight as information from spills that do occur. They noted that the data would be even more informative if there were a mechanism to identify near misses and to track information on leading indicators that are detected before a leak occurs. Unfortunately, there are no reporting requirements in place to allow regulators to track this data. Appendix F includes a methodology offered by one of the Expert Panel members for conducting root cause spill investigations that would provide much of the information necessary to populate the data fields recommended here. As discussed in Recommendation #5, many of these analytic techniques can also be applied as part of an ongoing, "rolling risk analysis" program.

Based on the Expert Panel members' firsthand knowledge of the North Slope operator's data collection as well as the information provided by operator representatives during the Expert Panel meeting, it was concluded that much of the data described above is likely already being captured by the operators. However, there is no mechanism for transferring that information in a comprehensive form to ADEC or other regulators. Likewise, results of operator-conducted root cause analyses are not necessarily shared with ADEC or other regulators. It was noted that of the spills considered for this analysis, there had been a joint investigation performed on only 2 of the 70 spills of over 1,000 gallons. The Expert Panel suggested that ADEC revise their spill reporting requirements to capture more of the information that is pertinent to a spill risk assessment. Such a requirement would then ensure that operators specifically compile this information, and ensure that the information is properly reported to the regulatory agencies.

The Expert Panel also noted that it would be useful to the overall risk management picture to understand how operators analyze their own data regarding common causes of integrity loss and how they apply that analysis to their internal decision-making regarding risk management programs. Similarly, the Expert Panel expressed an interest in the extent to which operators are sharing information among themselves about common conditions, in order to identify whether there are similarities in failure rates and causes for similar infrastructure components across operators. It was agreed that increased information sharing, both between operators and regulators and among operators, could result in system-wide risk reductions. It was also recommended that operators work together to develop a standardized vocabulary for failure causes, so that they could more easily combine and compare their internal data sets.

The Expert Panel cited the annual corrosion reports (ADEC April 2010b, http://www.dec.state.ak.us/spar/ipp/corrosion/index.htm) compiled by North Slope operators under the North Slope Charter Agreement (ADEC March 2010a, http://www.dec.state.ak.us/spar/ipp/docs/Charter%20Agreement.pdf) as an example of where operator data was presented in a manner that made it difficult to draw useful information regarding how best to target future mitigation. In reviewing these corrosion reports, the Expert Panel noted that it was unclear how corrosion coupons were utilized to make decisions about preventing spills caused by loss-of-integrity. The Panel also expressed an interest in understanding the chain of events underlying some of the near misses (saves) reported in the annual corrosion reports filed by North Slope operators, but they found that the manner in which the data was aggregated in the corrosion reports made it difficult to examine from this perspective. In reading the reports, it was very clear the type of activities that are ongoing to manage and evaluate corrosion, but it was less clear how these activities fed back into the system of assessing and managing spill risks from loss-of-integrity.

The Expert Panel agreed that the North Slope Spill data set and analysis described in this report could be a starting point for enhanced data compilation and analysis. Five or ten years down the road, a more robust data set resulting from enhanced data collection and reporting could provide more insight into better means to reduce future occurrences of spills from North Slope oil transmission pipelines and flowlines.

Implementation

The Expert Panel identified several possible mechanisms for implementing the recommendation to improve data collection. Further consideration of the analysis and recommendations in this report may lead to identification of additional implementation mechanisms.

- Enhance and expand ADEC's database with additional data fields based on the information gathered in this analysis and identified by the Expert Panel as salient to future prevention and mitigation.
- Develop a data form that facilitates the collection of data that provides information about spill causes and that will facilitate analyses that inform on the effectiveness of operators' spill prevention and integrity management activities. Encourage common terminology to describe causal categories.
- Articulate data needs to operators with enhanced requirements for final reporting of all North Slope oil transmission and flowline spills resulting from a loss-of-integrity. Provide specific reporting forms that streamline the process of operators compiling the data and that correlate to the data entry fields for the ADEC database to simplify data entry. Establish a mechanism to ensure that reports are provided as required with all data fields completed.
- Periodically evaluate spill data to look for trends and identify any areas where mitigation or prevention activities should be targeted.
- Require root cause analysis for all oil spills above a certain threshold (1,000 gallons) to capture key information on root and contributing causes. Do not allow "other" to be used as a cause category.

5.5 Proactive Risk Analyses

Recommendation

The Expert Panel recommends:

> *Conduct regular and ongoing proactive risk analyses to maintain systems at a prescribed level of safety, and share information from risk analyses among operators and with regulators.*

This recommendation is targeted at North Slope crude oil infrastructure operators with oversight from regulators.

Justification

In order to maintain a system at a prescribed level of safety, it is not enough to only examine that system when failures occur (i.e. root cause analysis in response to an oil spill or leak). It is equally important to conduct "rolling" risk analyses, where operators identify potential hazards within their system. This is particularly important in the event of significant changes to the system, but should also be conducted regularly to validate assumptions regarding the effectiveness of protective barriers to prevent failures.

Discussion

The Expert Panel discussed the fact that there are a number of requirements in place already for pipeline operators to conduct risk assessments whenever significant changes are made to operation or maintenance activities.[4] These requirements are typically part of a larger "management of change" (MOC) system that is intended to ensure that safety and prevention programs remain relevant to the types and severity of risks within a facility. Operators are also required under federal regulations to monitor for any conditions that could present a hazard to the safe operation of the pipeline system, and to report these conditions to the federal government (DOT) and take corrective actions until the condition can be remedied. North Slope pipeline segments that do not fall under DOT regulations are not subject to this requirement.

This concept of a "rolling" risk analysis – ongoing system evaluation in order to determine whether the level of risk of leaks or failures has changed – is essential. Safety and prevention systems designed when a pipeline is first constructed may require adjustments as the pipeline ages and operating parameters change. Ongoing risk analysis provides a mechanism to ensure that safety and prevention programs are suitable to the type and scale of risks present. The resiliency of prevention and mitigation programs must be regularly evaluated to determine whether they are still acting as effective barriers to loss-of-integrity. The need for ongoing risk assessment within the operating systems is especially important given the mandate for the Expert Panel – to provide recommendations on appropriate risk reduction measures to promote safe and reliable operation of North Slope crude oil infrastructure through another generation of production.

Rolling or ongoing risk analyses are an important tool for periodically evaluating assumptions that may have been made during the initial engineering designs of a facility. Operators must regularly validate early assumptions about the service life, or planned/expected useful lifespan, for a given system or component of that system. Determination of service life is an integral part of the design

4 For example, 49 CFR Parts 190-199 require the operator of a DOT-regulated pipeline to assess risks associated with changes to operations or maintenance activities and to correct any conditions that could adversely impact safe operation of pipelines. 29 CRF 1910 contains requirements for job safety analyses and work hazard assessments to evaluate risks to human health and worker safety, and to re-evaluate whenever operations or maintenance practices change.

process, but changes in system characteristics, operations, or maintenance may impact the expected service life. These changes may also impact the effectiveness of prevention measures and barriers to loss. Ongoing operations and maintenance practice can also impact service life, and consequently may enhance or detract from preventive measures or loss interventions. Understanding the nature of these changes and adjusting the system accordingly is a complex, ongoing challenge, and one where traditionally, regulators have had limited opportunity to provide oversight or direction.

To illustrate the potential for service life assumptions to impact spill risks, the Expert Panel used the example of a pipeline that is originally designed for steady state operation with little pressure fluctuation. If, after several years, the original operational parameters are changed and the pipeline sees large and frequent pressure fluctuation, it could significantly impact the line's service life and lead to unexpected failure. Ongoing analyses of how such changes in operating parameters impact systematic risks would provide an opportunity to erect additional barriers to prevent failure of this pipeline.

The Expert Panel discussed the role of inspectors in this process of ongoing risk analysis. They agreed that in order to be effective, inspectors must have appropriate training and experience to be able to evaluate the effectiveness of prevention systems and barriers to failure, and must have the tools and procedures in place to capture this information during routine inspections. They noted the challenge of training inspectors to the level required to conduct these types of assessments, since a high level of understanding of the system engineering is required.

Implementation

The Expert Panel identified several possible mechanisms for implementing the recommendation to conduct regular and ongoing proactive risk analyses to maintain systems at a prescribed level of safety, and share information from risk analyses among operators and with regulators. Further consideration of the analysis and recommendations in this report may lead to identification of additional implementation mechanisms.

- Operators should develop "rolling risk assessment" programs where they systematically evaluate the failure risks and effectiveness of existing barriers within their system, in an attempt to anticipate and prevent future spills.
- One component of rolling risk assessment is to periodically assess the remaining service life of a pipeline system. Key activities to this assessment would be:
    - Capture and understand those assumptions used to calculate the initial service life;
    - Collect operational and repair data;
    - Validate initial service life assumptions; and
    - Note any and all changes to the original operational parameters
- Operator maintenance programs must be reviewed annually to ensure the current procedures are effective in assuring pipeline safety. Additionally, operators and pipeline employees should be trained accordingly to evaluate how changes in the system may interact with prevention systems and barriers to failure.
- Provide regulators with better access to North Slope operator practices for ongoing risk analysis. This may require regulatory or statutory changes.

5.6 Oversight of Corrective Actions and Preventive Measures

Recommendation

The Expert Panel recommends:

Oversee implementation of corrective or preventive measures to evaluate their impact and effectiveness.

This recommendation is targeted at regulators and North Slope crude oil infrastructure operators

Justification

The current regulatory inspections focus and scope appears to be directed toward compliance monitoring. The focus and scope of these inspection activities should be expanded to include monitoring the effectiveness of corrective actions to prevent recurrence and effectiveness of mitigation measures taken. This is one way to "close the loop" and ensure that preventive or corrective actions are being implemented as intended.

Discussion

The Expert Panel included several individuals with extensive knowledge of US and Alaska pipeline integrity oversight regimes. The Panel observed that the existing oversight regime monitors compliance with lease terms, regulatory requirements, and other directives. Inspections also monitor whether operators comply with prescribed corrective actions and mitigation measures. However, oversight activities do not attempt to determine whether the corrective actions or mitigation measures taken have been effective in achieving the objective of reducing spills from loss-of-integrity. The Expert Panel agreed that oversight must involve more than simply ensuring that operators are doing what they are supposed to be doing; it must also evaluate whether what they are doing is accomplishing the established goals.

The recommendation for enhanced oversight to evaluate the effectiveness of corrective or preventive measures presumes that the data collection and analysis process described in Expert Panel Recommendation #4 have been implemented. It is not possible to begin to evaluate the effectiveness of corrective actions or preventive measures without reliable data on trends and causality of loss-of-integrity spills and incidents. Therefore, the first step is to identify the data parameters needed to provide meaningful information about changes to spill statistics, and the ability to correlate that data to evaluate the impact of mitigation measures and corrective actions.

While the process of compiling and analyzing the data needed to inform on the effectiveness of mitigation measures and corrective actions may require enhanced efforts at both data collection and root causes analysis, these types of effectiveness reviews are a recognized component of thorough root cause analysis and critical to effective risk management. Completing corrective and mitigating actions is not an assurance of the effectiveness of those actions.

Currently, there is no mechanism in place to require that North Slope operators or regulators conduct effectiveness reviews as part of their State-required spill investigations and follow-up. Similarly, there is no mechanism in place for the State to evaluate the effectiveness of mitigation measures or corrective actions. Yet, this is a key component of the feedback loop connecting the spill event with the subsequent investigation and ultimately the corrective actions taken to prevent future events with common causes. Evaluation of whether or not those corrective measures achieve their intended goal is the final step in establishing a system where operators and regulators reduce systemic risks.

Figure 5-2 shows an example of the type of corrective action feedback loop contemplated by the Expert Panel. Effective corrective actions should prevent the types of contributing causes associated with past spills.

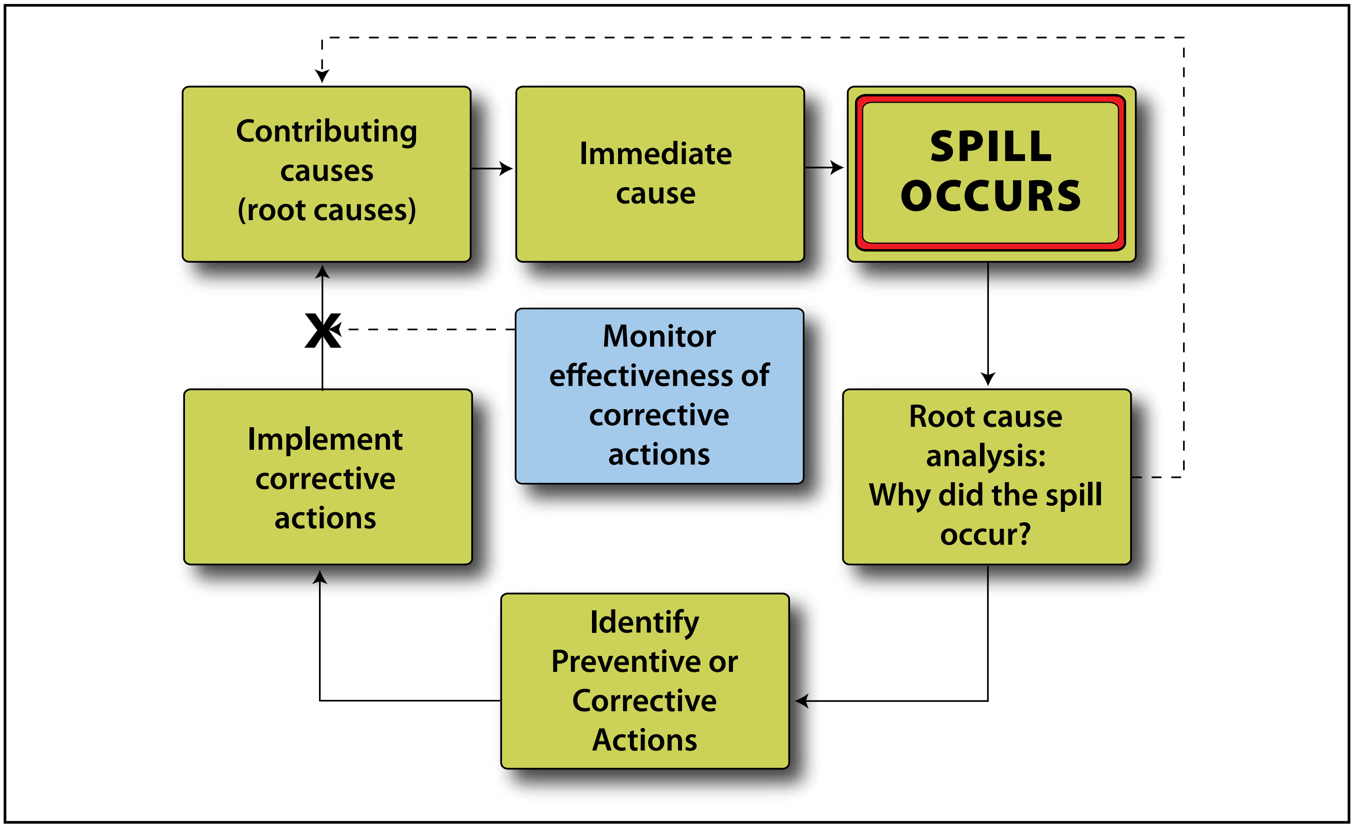


Figure 5-2. Example of corrective action feedback loop to prevent future spills.

In discussing various oversight and inspection regimes, the Expert Panel concurred that one major problem is that most inspectors focus on compliance and are not trained or conditioned to evaluate the effectiveness of mitigation measures or corrective actions. Such evaluations are certainly more complex and may require significant additional training and capabilities, but the potential gains in terms of reduction of spills could be substantial.

Regulations and compliance are not always effective at reducing the risks of spills. For example, the Expert Panel cited the US Department of Transportation (DOT) requirement under 49 CFR 195.420 for mainline valve testing as an example of compliance vs. effectiveness oversight. DOT's valve maintenance requirements are as follows:

- Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.
- Each operator shall, at intervals not exceeding 7½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.
- Each operator shall provide protection for each valve from unauthorized operation and from vandalism.

To demonstrate compliance with the twice-a-year inspection, DOT has traditionally required the pipeline operator to partially "stroke" the valve (move the sealing element toward closure) and monitor the valve stem for movement. The Panel noted that this inspection method only measures 10% to 20% of the valve's full range, does not require the valve to be fully closed, and doesn't require any measurement of the valve's sealing ability. An operator could be in full compliance with the regulation, and yet their valve could fail because the inspection requirement does not demonstrate that the valve is functioning effectively, only that it passes one specific test. While the intent of the regulation is to ensure that the valve is functioning such that it can stop the flow of liquid, the inspection procedure does not necessarily demonstrate that the valve will seal to stop the flow of product, which is the intended purpose of a mainline valve.

A common theme throughout the discussions and recommendations of the Expert Panel was the need for better information sharing and knowledge transfer at both the regulator and operator levels. The Expert Panel discussed the fact that the State should also look to oversight and information-sharing models in place in other US government agencies as well as foreign jurisdictions. There may be opportunities for knowledge transfer among these bodies if they are provided with a forum to share their experience and approaches to measure the effectiveness of mitigation measures and compliance actions. Similarly, there was some discussion about how other industries approach oversight. The Nuclear Regulatory Commission (NRC) was identified as a regulatory body that oil and gas regulators might look to in modeling oversight programs and activities. NRC has much clearer "free and unfettered" access to industry data than do State and federal regulators in the oil and gas sector. Regulatory or statutory changes may be required to provide broader access to industry data (outside of spill reporting requirements).

Implementation

The Expert Panel identified several possible mechanisms for implementing the recommendation to oversee implementation and evaluate effectiveness of corrective actions or preventive measures. Further consideration of the analysis and recommendations in this report may lead to identification of additional implementation mechanisms.

- Require operating companies to include effectiveness review plans following the implementation of corrective actions and mitigation measures.
- Require operators to include evaluations of the effectiveness of corrective actions and the mitigation measures in their annual reports and in their oil discharge prevention and contingency plans.
- Oversight agencies should train inspectors to expand the scope and focus of their inspection activities to include an evaluation of the effectiveness of implementation of the corrective actions and the mitigation actions by the operators.
- State of Alaska regulators should interact with other state and federal regulatory bodies to examine how they are benchmarking their industry and to try to learn from or borrow practices from other industries or other jurisdictions.

5.7 Escalate Oversight Based on Spill Occurrences.

Recommendation

The Expert Panel Recommends:

> *Establish a system of escalated enforcement to enhance and increase regulatory attention on pipeline operators that have spills on the North Slope.*

This recommendation is targeted at regulators.

Justification

The data presented in this report suggests that, overall, loss-of-integrity spill occurrence rates and severity have been steady since 1995, with an apparent upward trend for spills over 1,000 gallons, despite enhanced attention by operators to corrosion reduction. Regulators report a desire to impose increased regulatory oversight but cite limited resources as a barrier. Escalated enforcement would provide a mechanism to tailor or focus oversight activities to those operators or activities that contribute most significantly or consistently to overall spillage rates. A similar process of increased regulatory attention is successfully being implemented by the NRC to achieve safety performance improvement in the nuclear power industry.

Discussion

Based on the data presented to the Expert Panel, it appears that since 1995, spills from loss-of-integrity to North Slope piping have continued to occur at a rate of approximately 44 spills per year, with an average spill volume of approximately 1,800 gallons per spill. The Panel noted that with the exception of flowlines there has been no identifiable reduction in either the number or volume of spills between 1995 and present, in spite of continuing efforts by both regulatory agencies and operating companies. In fact, the data showed a slight trend upward in the volume of spills occurring on the North Slope, with the number of higher volume spills (over 1,000 gallons) also increasing between 1995 and the present.

The Expert Panel interpreted this data as suggestive of the fact that efforts by the operating companies to reduce the number or volume of spills per year from North Slope pipeline loss-of-integrity have shown limited results. Yet, the operating companies report increased efforts and attention focused on preventing leaks due to corrosion. The regulatory agencies have reported a desire to increase regulatory attention on preventing loss-of-integrity spills, although they also cite resource challenges (lack of both personnel and funding) as factors limiting their ability to increase regulatory attention.

As discussed in Recommendations 1 and 2, there is currently limited information available to regulators regarding root cause analysis and accident investigation into larger spills, and joint investigations are conducted very infrequently. Root cause analyses and accident investigations conducted by the operator are not likely to consider gaps in regulatory oversight that may have been contributing causes to the spill. Escalated enforcement provides a mechanism for regulators to play a more active role in focusing their limited resources on examining root and contributing causes of major events as well as high frequency failures from a specific operator. This can be accomplished without any major regulatory or legislative changes.

Implementation

The Expert Panel recommended an implementation program that could be adopted by State regulators through their enforcement discretion.

- The principal of escalated enforcement is that operators who have one large spill or a cluster of smaller spills within a calendar year would be subject to enhanced oversight and inspection. Root cause investigations would be automatically triggered for larger spills, and enhanced inspections would be conducted (with operators covering all associated costs) for large spills or multiple smaller spills in a 12-month period.
- Categorize North Slope loss-of-integrity spills for the purpose of escalated enforcement as follows:
    - Category 1: A single spill of 1,000 gallons or more.
    - Category 2: Three (3) spills of 100 gallons or greater linked to the same operator in the same field (during a 12 month period from the date of the first spill)
    - Category 3: Five (5) spills of 55 gallons or greater linked to the same operator in the same field (during a 12 month period, from the date of the first spill)
- Established enhanced enforcement procedures based on spill Category. An example of such procedures are:
    - Category 1: Root cause investigation and enhanced inspection. Form an interagency team (State and/or federal personnel or contractors) to conduct an independent root cause investigation with recommendations to prevent recurrence and recommendations to enhance the regulatory process where applicable. Set a reasonable time limit for production of final report (e.g. 60 days, 90 days). Establish an enhanced inspection schedule for no less than 12 months following the spill, or until satisfactory improvement has been achieved. Require the responsible operating company to cover all costs associated with hiring contractor support to carry out the additional inspections, reportable to the oversight agency.
    - Category 2: A representative of the oversight agency performs a detailed review of the operator's root cause analyses to determine adequacy and request additional analysis, as needed. Establish an enhanced inspection schedule for no less than six months following the spill, or until satisfactory improvement has been achieved. Require the responsible operating company to cover all costs associated with hiring contractor support to carry out the additional inspections, reportable to the oversight agency.
    - Category 3: Establish an enhanced inspection schedule for no less than 6 months following the spill, or until satisfactory improvement has been achieved. Require the responsible operating company to cover all costs associated with hiring contractor support to carry out the additional inspections, reportable to the oversight agency.
- Within five years of completion of the escalation enforcement process, perform an effectiveness review to determine whether the escalated enforcement efforts have achieved actual performance improvements related to the frequency or severity of spills in the specific areas affected.

CONCLUSIONS 6

The goal of the North Slope Spills Analysis was to reduce the frequency and severity of future spills from North Slope crude oil piping infrastructure integrity loss. The process selected to achieve this goal involved analyzing the data trends in loss-of-integrity spills from crude oil piping infrastructure on the North Slope and developing recommendations for mitigation measures to interrupt any negative trends.

The analysis presented in Section 4 considers trends in the frequency and severity of spills for the entire 640 loss-of-integrity spills in the data set, based on infrastructure regulatory category, leak rates, age at failure, leak detection, spill impacts, and spill causes. Section 5 presents seven Expert Panel recommendations for mitigation measures that may lead to a reduction in the frequency and severity of loss-of-integrity spills from North Slope crude oil infrastructure, based on the data from past spill occurrences.

The relationship between infrastructure age and the frequency and severity of spills from that infrastructure was a major concern of the Alaska legislature. Based on this analysis, there are significant trends to suggest that the probability of spills from flowlines or oil transmission pipelines can be correlated to the age of the infrastructure. Also, spill data for facility oil piping and wells does show some characteristics that could be related to aging.

The two largest spills in the data set complicated some of the statistical tests, and also skewed some of the analysis regarding which infrastructure components contribute most significantly to spill severity. The two largest spills came from storage tanks and oil transmission pipelines, so that any volumetric analysis tended to show those two infrastructure categories as problematic. However, absent those two large spills, spill trends from storage tanks and oil transmission pipelines suggest that these categories are not frequent sources of spills. Conversely, the frequency of spills from flowlines and facility oil piping is significantly higher than other regulatory categories, and while there have not been any flowline spills on the 200,000+ gallon scale, the average volume of flowline spills is twice the average of all spills. So, the data suggests, based on the trailing indicator of past spill occurrences, that flowlines and facility oil piping have a higher loss-of-integrity frequency and therefore might require additional regulatory attention.

Based on the data alone, it appears that measures for reducing spill numbers would be most effective for facility oil piping, process piping, and wells, while measures for reducing spill severity should focus on flowlines. Additional study may be needed to better understand the potential that infrastructure age is a contributing factor to spills from facility oil piping and wells.

Upon reviewing the data presented in this report and considering information provided from regulators and operators, the Expert Panel identified seven recommendations, which are discussed in Section 5 of this report. The Expert Panel provided concrete suggestions for implementing these recommendations, requiring action from regulatory agencies, operators, or both parties.

Commonalities exist between the Expert Panel recommendations, which were developed based on early analysis of the North Slope Spills data, and other comments and recommendations compiled earlier in the Alaska Risk Assessment project cycle. While the Phase 1 methodology for a quantitative risk assessment (DoyonEmerald and ABS, 2009), discussed in Section 1 of this report, was replaced with the North Slope Spills Analysis, many of the issues that were raised during the Phase 1 methodology public and peer review are addressed in this report.

Public comments included recommendations for enhanced field assessments and infrastructure inspections, to gain a "boots on the ground" perspective on the integrity of the North Slope crude oil infrastructure. While such a field-intensive inspection program was not feasible during the Alaska Risk Assessment and was not cogent to the North Slope Spills Analysis, many of the recommendations made by the Expert Panel would likely result in enhanced field inspections. In particular, Expert Panel recommendation #2 for enhanced Integrity Management Program activities for flowlines would apply the federal DOT model for pipeline integrity to North Slope flowlines, leading to enhanced inspections to detect potential problems before they can cause a loss-of-integrity. Expert Panel recommendation #5 may also provide key information about system-wide risks or weaknesses that may help to focus enhanced inspections and field assessments on areas or infrastructure components at highest risk of an integrity loss.

Public comments also addressed the fact that during Phase 1 of the Alaska Risk Assessment, significant challenges were encountered in compiling the data needed for a comprehensive engineering risk assessment, because such data was maintained by operators and there was no clear path to access this data. The North Slope Spills Analysis was designed to utilize publicly available data, with review and validation by industry. An important outcome of the North Slope Spills Analysis was a systematic examination of the depth and limits of spill data as it is currently compiled and maintained by the State of Alaska. Expert Panel recommendation #4 identifies opportunities to improve current data compilation, emphasizing the need for better causal data to focus future mitigation programs. Moving forward, if the State of Alaska implements the recommendation to improve data collection, there will be a more robust data set available to support future studies and to begin to measure the effectiveness of mitigation programs. Expert Panel recommendations #1, 2, 5, and 6 will also result, to varying degrees, in better information-sharing between operators and regulatory agencies. Over the long term, regulatory agencies will develop a better understanding of the integrity of operator infrastructure and the operations and maintenance programs in place. A better understanding of such nuances will also help future spill data analyses and may provide insight into data trends like the one noted here where one infrastructure category (flowlines) had the highest frequency of severe spills while the very largest spills occurred from infrastructure categories (storage tanks and oil transmission pipelines) with much lower overall spill frequencies.

Both public and peer review comments (from the Transportation Research Board of the National Academy of Sciences) indicated that the original Alaska Risk Assessment methodology was fundamentally flawed because it would not provide any insight into how mitigation measures could be applied to reduce the risks identified in the study. The TRB specifically recommended that the State consider forward-looking risk management programs. While the North Slope Spills Analysis analyzed historical spill occurrence rates, it provided a foundation for Expert Panel recommendations that address risk management systems and processes that would mitigate the risks identified in the spills analysis.

A companion study to the North Slope Spills Analysis, published by Cycla Corporation (2010),[1] discusses candidate risk management and oversight systems based on models in place in other jurisdictions. Recommendations for Alaska are presented in two general categories: candidate future actions in the risk management area, and candidate changes the Alaska Department of Environmental Conservation (ADEC) might make.

The Cycla report recommends five candidate future actions for risk management:

- Focus on evolution and refinement of existing oversight system and processes rather than radical revision of the system;
- Require operators to implement strategic management processes to monitor and learn from experience, anticipate changes in the operating environment, and systematically allocate resources to manage recognized risks;
- Expand mandatory reporting to support improved oversight agency understanding of the effectiveness of operators' internal management systems;
- Impose additional requirements for operator management systems by promulgating new regulations that either reference existing standards or prescribe specific requirements; and
- Strengthen the role of Alaska oversight agencies in evaluating underlying risk causes and use the resulting improved understanding of key causal factors to tailor additional requirements.

There is significant commonality in what these recommendations are designed to accomplish, and considerable overlap between the five recommendations in the Cycla report and the seven recommendations from the North Slope Spills Analysis Expert Panel. The primary purpose of both sets of recommendations is to strengthen the Alaska regulatory agency knowledge and awareness of risks, and to improve agency access to information on the operators' perspective on risk as well as on their plans to manage that risk. More effective management of these risks will result in a reduction to the frequency and severity of spills due to loss-of-intgerity from North Slope crude oil infrastructure.

1 Cycla Corporation. (2010). "Review of Select Foreign and Domestic Approaches to Oversight and Management of Risk and Recommendations for Candidate Changes to the Oversight Approach for the Alaska Petroleum Transportation Infrastructure." Report to Alaska Department of Environmental Conservation.

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APPENDICES

Appendix A: Acronyms, Abbreviations and Glossary

Appendix B: Data Forms Used by North Slope Spills Investigators

Appendix C: North Slope Piping Infrastructure Catalogue

Appendix D: North Slope Crude Oil Piping Spills Data Set & Summary of Largest Spills

Appendix E: Expert Panel Record

Appendix F: Background & Reference Materials Developed by Expert Panel Members

Appendix G: Production Statistics from North Slope Oil Fields

Appendix H: Statistical Analysis of Alaska North Slope Spill Data

APPENDIX A

A.1 Acronyms and Abbreviations

3P	Three phase
AAC	Alaska Administrative Code
ABS	American Bureau of Shipping
ADEC	Alaska Department of Environmental Conservation
AGST	above-ground storage tank
AK	Alaska
AOGA	Alaska Oil & Gas Association
AOGCC	Alaska Oil and Gas Conservation Commission
ARA	Alaska Risk Assessment
ARCO	Atlantic Richfield Company
ASME	American Society of Mechanical Engineers
BAT	Best available technology
bbl	barrel
BC	British Columbia
BEST	Board on Environmental Studies & Toxicology
BLM	Bureau of Land Management
BPXA	BP Exploration, Alaska
C-plan	Oil spill contingency plan
CCA	Common cause analysis
CE	Corrosion, external
CI	Corrosion, internal
CIC	Corrosion Inspection & Chemicals
CP	ConocoPhillips
CPAI	Conoco Phillips Alaska, Inc.
CPM	Computational pipeline monitoring
CU	Corrosion, unknown
CUI	Corrosion under insulation
DCF	Data collection form
DNR	Department of Natural Resources
DOT	Department of Transportation
EIS	Environmental Impact Statement

EPA	Environmental Protection Agency
FL	Flowline
FOP	Facility oil piping
GIS	Geographic information systems
GKA	Greater Kuparuk Area
ID	Identification
ILI	In-line inspection
IM	Integrity Management
IMP	Integrity Management Program
JPO	Joint Pipeline Office
LDS	Leak detection system
LLC	Limited Liability Company
mm bbl	Million barrels
MOC	Management of change
n	Number
NACE	National Association of Corrosion Engineers
NAS	National Academy of Sciences
NRC	Nuclear Regulatory Commission
NSS	North Slope Spills
OE	Operator error
OPMG	Oil Pipeline Management Group
OSHA	Occupational Safety and Health Administration
OTP	Oil transmission pipeline
PFD	Process flow diagram
PHMSA	Pipeline and Hazardous Materials Safety Administration
PID	Piping and instrumentation diagram
PP	Process piping
PRB	Polar Research Board
PSIO	Petroleum Systems Integrity Office
PW	Produced water
QA/QC	Quality assurance/quality control
QRA	Quantitative Risk Analysis or Assessment
RDS	Research and Development Solutions
RFID	Radio frequency identifier
SAOT	State Agency Oversight Team
SPCC	Spill Prevention, Control and Countermeasures
SPE	Society of Petroleum Engineers
TAPS	Trans Alaska Pipeline System
TE	Thermal expansion
TRB	Transportation Research Board
US	United States

USEIA	United States Energy Information Administration
VMT	Valdez Marine Terminal
VS	Valve/seal failure
W	Well
WNS	Western North Slope

A.2 Glossary of Terms

Aboveground Storage Tank {18 AAC 75.065; 18 AAC 75.990(165)}: for the purpose of 18 AAC 75.065, 18 AAC 75.066, and 18 AAC 75.075, means a container, including a storage and surge tank, that is used to store bulk quantities of oil and that has a capacity greater than 10,000 gallons; with the exception of a field-constructed underground storage tank, "aboveground oil storage tank" does not include a process pressure vessel or underground storage tank within the meaning of AS 46.03.450.

Contributing Cause: those factors that contribute or lead to the immediate cause and sometimes referred to as "root cause".

Corrosion {18 AAC 75.990(168)}: means the deterioration of metal from the loss of positive charged metal ions from the metal's surface into an electrolyte. Sub-categories include:

Internal corrosion,

External corrosion.

Facility Oil Piping {18 AAC 75.080; 18 AAC 75.990(171)}: piping and associated fittings, including all valves, elbows, joints, flanges, pumps, and flexible connectors, originating from or terminating at

(A) an aboveground oil storage tank regulated under 18 AAC 75.065 or 18 AAC 75.066 up to the

(i) union of the piping with a fuel dispensing system;

(ii) marine header;

(iii) fill cap or fill valve;

(iv) forward pump used to transfer oil between facilities, between adjacent pump stations, or between a pressure pump station and a terminal or breakout tank; or

(v) first flange or connection with a tank truck loading area or with a loading rack containment area, or;

(B) an exploration or production well, up to the:

(i) choke or valve interconnection with a flowline; or

(ii) first valve or flange inside a processing unit boundary

Failure: refers to the state or condition of not meeting a desirable or intended objective. For the purpose of this analysis through-wall pipe damage that causes loss of product.

Flat File: is a plain text or mixed text binary file which usually contains one record per line.

Flowline {18 AAC 75.047; 18 AAC 75.990(173)}:

(A) means piping and associated fittings, including all valves, elbows, joints, flanges, pumps and flexible connectors,

(i) containing liquid oil;

(ii) located at a production facility; and

(iii) that is installed or used for the purpose of transporting oil between a well pad or marine structure used for oil production and the interconnection point with a transmission pipeline; and

(B) includes all piping between interconnections, including multi-phase lines and process piping, except

(i) facility oil piping, and

(ii) transmission pipelines.

Flow Rate: the maximum production rate below which the production of solids along with the produced fluid is uniform.

Immediate Cause: action or inaction that immediately preceded and led to the spill and/or event or near miss. Also referred to as proximate cause and primary cause.

Inadequate Procedures/Policy: procedures or policies that are conflicting, ineffective, inaccurate, out-of-date or insufficient.

In-line inspection (ILI): pipeline inspection conducted using an instrumented vehicle that travels inside the pipeline usually propelled by the fluid in the pipe.

Insufficient personnel: failure to ensure that all required tasks can be done with adequate personnel of the proper skill level, physical ability, experience, or certification.

Integrity Management Program (IMP): A documented set of policies, processes, and procedures that includes, at a minimum, the following elements: a process for determining which pipeline segments could affect a high consequence area; a Baseline Assessment Plan; a process for continual integrity assessment and evaluation; an analytical process that integrates all available information about pipeline integrity and the consequences of a failure; repair criteria to address issues identified by the integrity assessment method and data analysis (the rule provides minimum repair criteria for certain, higher risk, features identified through internal inspection); a process to identify and evaluate preventive and mitigative measures to protect high consequence areas; methods to measure the integrity management program's effectiveness, and a process for review of integrity assessment results and data analysis by a qualified individual. (U.S. DOT)

Key Performance Indicator (KPI): is a measure of performance. Such measures are commonly used to help an organization define and evaluate how successful it is, typically in terms of making progress towards its long-term organizational goals.

Lack of planned maintenance program: failure to have company planned maintenance program.

Lack of Procedure/Policy: failure to have company procedures or policies.

Lack of Training: inadequate technical knowledge due to insufficient training or the absence of proper training of operational personnel.

Loss-of-integrity: A failure that leads to leakage of any fluids in the production stream, including mechanical failures and human errors.

Management of change (MOC): is a structured approach to transitioning individuals, teams, and organizations from a current state to a desired state.

Near miss: is an unplanned event that did not result in injury, illness or damage but had the potential to do so.

North Slope Oil Fields: the oil production and transportation locations within the North Slope Region.

North Slope Region {18 AAC 75.495(a)(9)}: that area encompassed by the boundaries of the North Slope Borough, including adjacent shorelines and State waters, and having as its seaward boundary a line drawn in such a manner that each point it is 200 nautical miles from the baseline from with the territorial sea is measures.

Oil transmission pipeline: See Transmission pipeline.

Oil Well {20 AAC 25.990(45)}: means a well that produces predominately oil at a gas-oil ratio of 100,000 standard cubic feet (scf)/stock barrel tank (sbt) or lower, unless on a pool-by-pool basis the commission establishes another ratio.

Poor engineering design: failure of design (within control of responsible party) to provide for safe operations under normal operating conditions, could include failure caused by faulty installation.

Poor oversight: failure of management to effectively oversee subordinates and/or lack of involvement, inspection, and communications.

Pigging: the act of forcing a device called a pig through a pipeline for the purpose of displacing or separating fluids, and cleaning or inspecting the line.

Pipe or Piping {18 AAC 75.990(177)}: means any hollow cylinder or tube used to convey oil.

Primary cause of failure: action or inaction that immediately preceded and led to the spill and/or event or near miss. Also referred to as immediate cause.

Process and instrumentation diagrams (P&ID): diagrams that identify spill and also next major piece of equipment- upstream and downstream, and are stamped by an engineer.

Process Piping: Piping that is not otherwise regulated by the State of Alaska.

Process Water (Oil Exploration and Production Operations): Process water includes seawater (and occasionally freshwater) and produced water. Seawater is injected into a formation to pressurize the reservoir and force the oil toward the oil production wells. Gelled water is seawater and freshwater that is mixed with a gelling substance to increase the viscosity of the fluid for a number of purposes. Seawater is also used to maintain the existing wells or to detect leaks in pipelines. Produced water is the water mixture consisting of oil, gas, and sand that is pumped from oil production wells.

Save: when the operators corrosion control group recommends a repair before a leak occurs.

Spills In-Scope: any reported spill of crude oil, produced water, sea water, or process water that was a result of loss-of-integrity during normal production operations.

Spills Out-of-Scope: any spill of crude oil, produced water, sea water, or process water that resulted from drilling, workovers, construction, or out-of-service maintenance. Also any spill of any other substance except crude oil, produced water, seawater, or process water.

Transmission Pipeline {18 AAC 75.055; 18 AAC 75.990(134)} **or Oil Transmission Pipeline**: means a pipeline through which crude oil moves in transportation, including line pipe, valves, and other appurtenances connected to line pipe, pumping units, and fabricated assemblies associated with pumping units; "transmission pipeline" does not include gathering lines, flow lines, or facility oil piping.

Well {20 AAC 25.990(73)}

(A) means a hole penetrating the earth, usually cased with steel pipe, and

(i) from which oil or gas, or both, is obtained or obtainable; or

(ii) that is made for the purpose of finding or obtaining oil or gas or of supporting oil or gas production; and,

(B) includes a well with multiple well branches drilled to different bottom-hole locations.

Workover: the repair or stimulation of an existing production well for the purpose of restoring prolonging or enhancing the production of hydrocarbons.

APPENDIX B

DATA FORMS USED BY NORTH SLOPE SPILLS INVESTIGATORS

B.1 Example of Spill Data Collection and Investigation Form: Blank

NORTH SLOPE CAUSE INVESTIGATION DATA COLLECTION FORM

NUKA ID:

ADEC File Number:
ADEC Spill Number
ADEC Cause Type:

Spill Date:

Regulatory Category:
Facility Name:
Line Operator:
Operator Spill Number:
Operator Equipment ID:

Reviewer:

Reviewer 2:

Review Date:

Pipeline Parameter Information
Nominal Wall Thickness:
Line Diameter:
Line Installation Date:
Measure of wall loss after spill:
Piping Location at Release:

- ☐ Above Grade
- ☐ Below Grade
- ☐ Sub-Sea

Is the pipeline insulated?

- ☐ **Yes**
- ☐ No

If "**Yes**" insulation type:____________
If "No" is the pipeline coated?__________

Can the pipeline be pigged?

- ☐ Yes
- ☐ No

Date of last pigging:
Type of pigging (cleaning or inspection):
Frequency of pigging?
Prior to the incident, was the pipeline pigged?

- ☐ **Yes**
- ☐ No

If **yes**, note type of pigging history (cleaning or inspection) in comments/notes?

Spill Location & Diagrams
Latitude:
Longitude:
How was Latitude & Longitude data collected?
Is there a Pipe & Instrument Diagram?

- ☐ Yes
- ☐ No

Is there a Process Flow Diagram for spill?

- ☐ Yes
- ☐ No

Leak Detection
How was the leak detected?

- ☐ Visual
- ☐ Odor
- ☐ Leak Detection System
- ☐ PID

How long was it leaking ? ________ [decimal day(s)]

Type of Cause Investigation

- ☐ TapRoot®
- ☐ Event and causal factor charting
- ☐ Change Analysis
- ☐ Barrier Analysis
- ☐ Five-Why's
- ☐ Comprehensive List of Cause®
- ☐ MORT
- ☐ Fault Tree Analysis
- ☐ None

Was the Investigation:

- ☐ Internal
- ☐ Joint with Agency Representatives
- ☐ Agency only
- ☐ 3rd Party

Immediate Cause Categories (May be multiple)

- ☐ Corrosion
  - External Corrosion
  - External at or near weld joints
  - Internal Corrosion
- ☐ Erosion
  - External
  - Internal
- ☐ Thermal Expansion
- ☐ Material Failure of Pipe or Weld
  - Construction, Installation or Fabrication related
  - Original Manufacturing-related
  - Vibration (wind-induced/slugging)
- ☐ Valve/Seal Failure
- ☐ Overpressure
- ☐ Operator Error
- ☐ 3rd Party Action
- ☐ Other (record in Comments/Notes)
- ☐ Not recorded by operator

Contributing Causes (May be multiple)

- ☐ Lack of Procedures/Policy
- ☐ Inadequate Procedures/Policy
- ☐ Inadequate Implementation of Procedure/Policy
- ☐ Lack of Training
- ☐ Poor oversight of personnel
- ☐ Insufficient personnel
- ☐ Lack of Planned Maintenance Program
- ☐ Poor Engineering Design
- ☐ Other, Explain in Notes

Environmental Impacts
Impact to Tundra

- ☐ YES
- ☐ NO

Area Impacted in Square Ft or Acres:
Impact to water (note whether water was frozen or liquid state)

- ☐ Frozen
- ☐ Liquid

NORTH SLOPE CAUSE INVESTIGATION DATA COLLECTION FORM **NUKA ID:**

Corrective Action Notes:

Comments/Notes:

DOCUMENTS USED TO COLLECT DATA:

- ☐ ADEC SITUATION REPORTS
- ☐ Incident Investigation Report
- ☐ Corrosion (Coffman) Reports
- ☐ Contingency Plan
- ☐ EPA SPCC Plan
- ☐ Other

STATUS OF REVIEW

- ☐ Pending Information
- ☐ Operator Review
- ☐ Review Completed/Submit for Data Entry

B.2 Example of Spill Data Collection and Investigation Form: Completed

NORTH SLOPE CAUSE INVESTIGATION DATA COLLECTION FORM

NUKA ID: 298

ADEC File Number:	300.02.005
ADEC Spill Number:	04399924401
ADEC Cause Type:	Structural/Mechanical
Spill Date:	8/31/2004

Regulatory Cat.:	Flowline
Facility Name:	GPB / Flow Station 3
Line Operator:	BPXA
Operator Spill No.:	04-184
Operator Equip ID:	06C-13B Common Line

Nuka Reviewer	TR
Review Date:	3/3/2010
Reviewer 2:	RW
Review Date:	4/22/2010

Facility Oil Piping
- ☐ Well Pad or Drill Site
- ☐ Process Center MOD to Oil Storage Tk

Flowlines
- ☐ WP (1st flange in MB to Edge)
- ☑ XCntry 3-Phase (Edge to 1st Flng at PC)
- ☐ Pig Launcher/ Receiver
- ☐ PW Pipeline to Injection

Oil Transmission Pipeline
- ☐ Line
- ☐ Pigging Launcher / Receiver

Process Piping
- ☐ MB Interconnection
- ☐ PC Interconnection
- ☐ Sea Water ☐ NG Line

X65

Pipeline Parameter Information
- Nominal WT: .281
- Line Diameter: 24
- Line Install Date: 1983
- Wall loss after spill:
- Piping Location at Release:
- ☑ Above Grade ☐ Sub-Sea
- ☐ Below Grade
- ☑ Pipe is Insulated (check if yes)? 2"
- ☐ Pipe is Coated (check if yes)?
- Type of Insulation and/or Coating: polyurethane/galvanized jacket
- With temporary facility
- ☒ Pipe Can be pigged (check if yes)?
- Date of Last Pigging: 2008
- Pigging Frequency: 3-5yr SMART PIG
- ☐ Pigged Prior to Incident (check if yes)?

Spill Location and Diagrams
- Latitude: 70.2508
- Longitude: 148.5713
- How was Lat/Long Collected: BP
- ☐ Is there a Pipe and Instrument Diagram (check if yes)?
- ☐ Is there a Process Flow Diagram for Spill (check if yes)?

Leak Detection
- ☒ Detected Visually? ☐ Detected by LDS?
- ☐ Detected by Odor? ☐ Detected by PID?
- How long was it leaking (decimal days)?:

Type of Investigation
- Type of Investigation?
- If Other, List:

Was the Investigation:
- ☒ Internal Investigation? ☐ Agency Only Investigation?
- ☐ Joint w/Agency Reps? ☐ 3rd Party Investigation?

Immediate Cause Categories (May be Mulitple)
- ☑ Corrosion
  - ☑ External Corrosion
  - ☐ External Corrosion at/near Weld Joints
  - ☐ Internal Corrosion
- ☐ Erosion
  - ☐ External Erosion
  - ☐ Internal Erosion
- ☐ Thermal Expansion
- ☑ Material Failure of Pipe or Weld galvanized jacket
  - ☐ Construction, Installation or Fabrication Related
  - ☐ Original Manufacturing-Related
  - ☑ Vibration (Wind Induced/Slugging)
- ☐ Valve/Seal Failure
- ☐ Overpressure
- ☐ Operator Error ☐ Not Recorded by Operator
- ☐ 3rd Party Action
- ☐ Other (Recorded in Comments/Notes

Contributing Causes (May be Mulitple)
- ☐ Lack of Procedures/Policy
- ☐ Inadequate Procedures/Policy
- ☐ Inadequate Implementation of Procedure/Policy
- ☐ Lack of Planned Maintenance Program
- ☐ Other, Explained in Notes
- ☐ Poor Engineering Design
- ☐ Lack of Training
- ☐ Poor Oversight of Personnel
- ☐ Insufficient Personnel
- If Other, List:

Environmental Impacts
- ☑ Tundra Impacted (check if yes)?
- Sq. Feet Impacted 30
- ☐ Liquid Water Impacted (check if yes)?
- ☐ Frozen Water Impacted (check if yes)?

NORTH SLOPE CAUSE INVESTIGATION DATA COLLECTION FORM

NUKA ID: 298

Corrective Action Notes:	GPB Cplan - Operations Area Managers to send list to CIC Team Leader of LDF'S, large common lines or any flowlines that have had a pressure surge or other event to have created enough line movement to damage insulation around a saddle so CIC can develop a plan for saddle inspections. CAUSE INV REVIEW: C-plan: Operations Area Managers to send list to CIC Team Leader of LDF's, large common lines or any flowlines that have had a pressure surge or other event to have created enough line movement to damage insulation around a saddle so CIC can develop a plan for saddle inspections.
Comments and Notes:	Tundra affected. External corrosion under insulation - pin hole. CAUSE INV REVIEW: #2 and #4: Commitment to Corrosion Monitoring Year 2004 report identifies flowline as 06C/138 and corrosion mechanism as CUI. #8 and #9: BPXA spill report states: "On Sept. 2nd a spill review was held at FS-3 to review the incident and to determine how the risk of a re-occurrence of this type failure could be reduced (see document attached to the Traction report). In attendance were FS-3 Operators, FS-3 Ops Lead, FS-3 AM, CIC TL, CIC piping inspector, ACS lead, the CIC technicians that found the leak, and the GPB, Environmental Advisor." #10: BPXA spill report states: "Approximately 30 sq ft of tundra were initially affected. No permanent tundra damage or scarring is expected. Note that initial notification estimated 10-15 gallons of crude to the tundra. Once identified, secondary containment was placed under the leaking common line. Additional produced water and crude continued to leak from the line into secondary containment. The final volume released from the line was estimated at approximately 153 gallons produced water and crude."

DOCUMENTS USED TO COLLECT DATA:

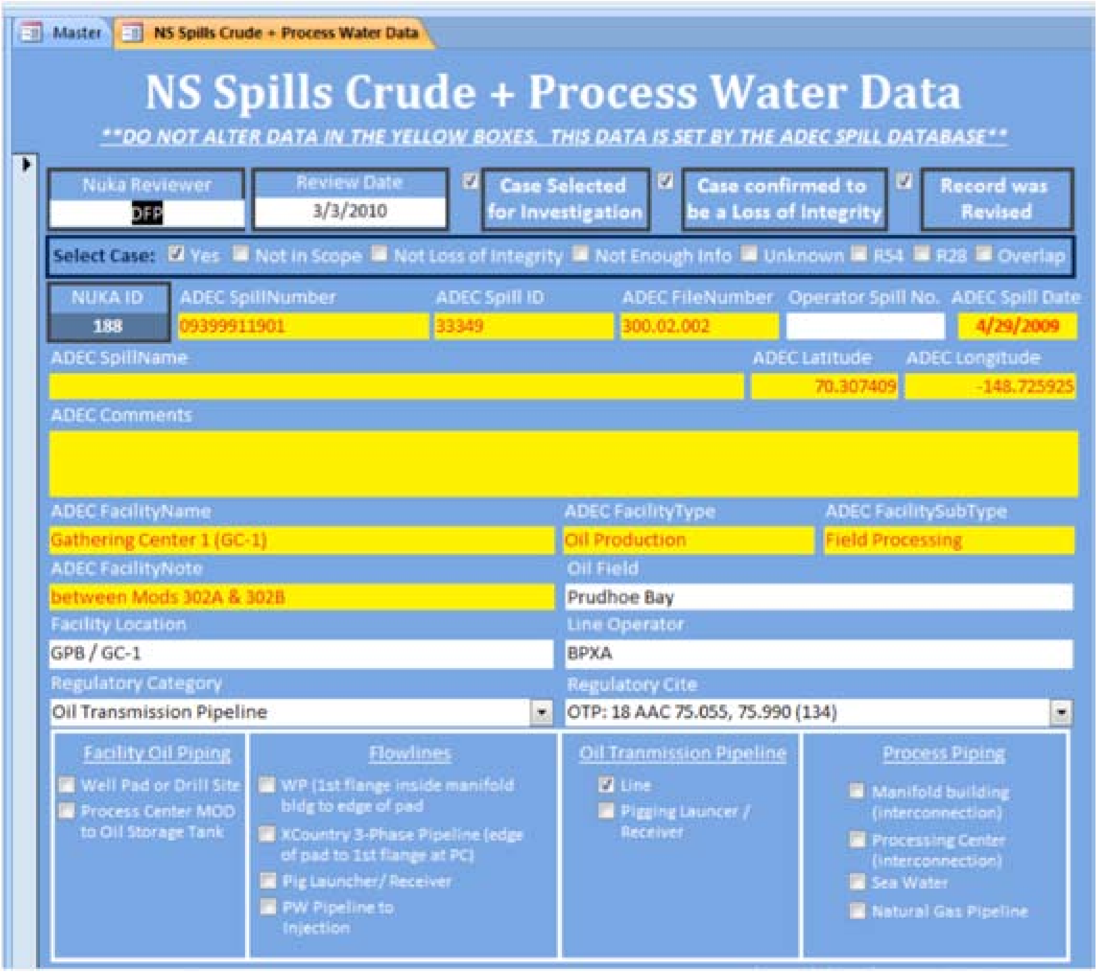
- ☐ ADEC SITUATION REPORTS
- ☐ Incident Investigation Reports
- ☑ Corrosion Reports
- ☑ Contingency Plan
- ☐ EPA SPCC Plan
- ☑ Other

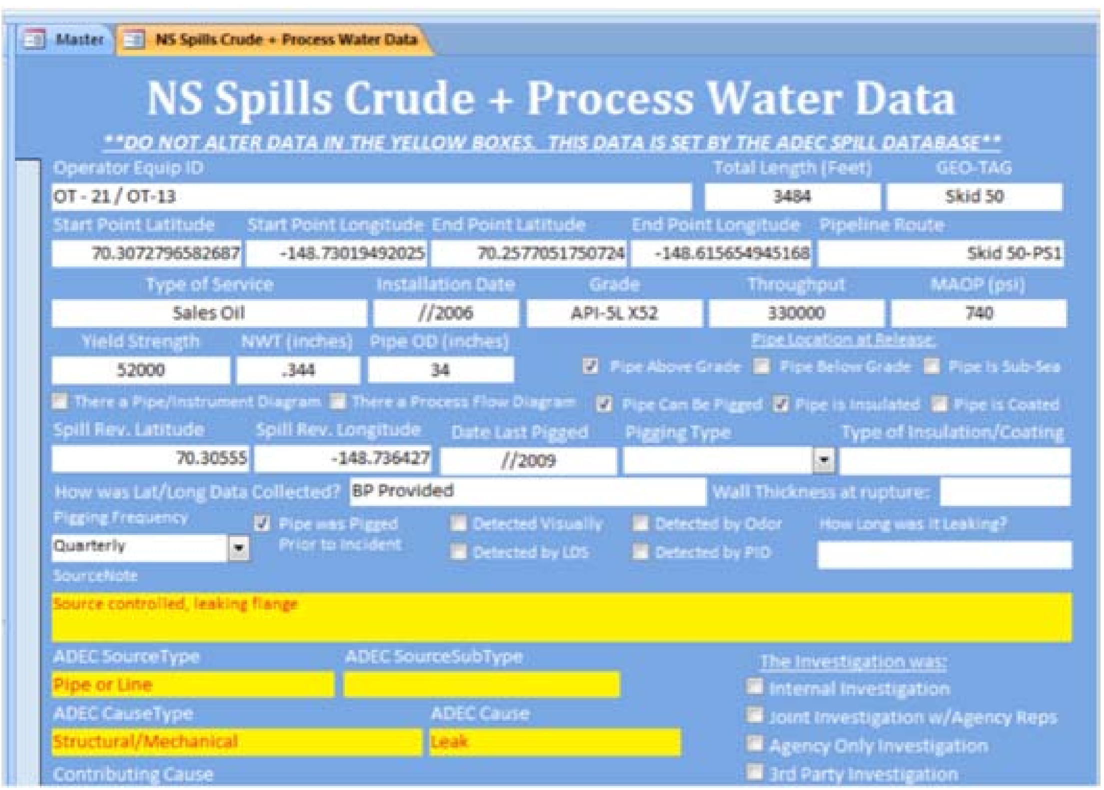
STATUS OF REVIEW:

- ☑ Pending Information
- ☐ Operator Review
- ☐ Review Completed / Submitted for Data Entr

If Other, List: Commitment to Corrosion Monitoring Year 2000; BPXA spill reports

B.3 Screen Shots from North Slope Spills Database Entry





APPENDIX C

C.1 Flowlines

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Prudhoe Bay	BPXA	FL-Produced H2O	PBU L- GC 2	84,138	12						
Kuparuk River	CP	FL-Produced H2O	KRU 2P- 2N	57,688	12	3000	65000	0.562			2001
Prudhoe Bay	BPXA	FL-Produced H2O	LPC - WPSD	43,446	18						
Kuparuk River	CP	FL-Produced H2O	KRU 2P- 2N	40,047	12	3000	65000	0.562			2001
Milne Point	BPXA	FL-Produced H2O	MPU J-TR 14 TI	32,500	6						
Colville River, Alpine	CP	FL-Produced H2O	AU CD 3- AU PF	27,790	8		65000	0.5			
Kuparuk River	CP	FL-Produced H2O	KRU 3O- CPF 3	27,167	10		55000	0.438			1987
Prudhoe Bay	BPXA	FL-Produced H2O	PBU DS 16- FS 2	27,084	16	3600	65000	0.688			1983
Prudhoe Bay	BPXA	FL-Produced H2O	PBU DS 17- FS 2	27,076	16						
Kuparuk River	CP	FL-Produced H2O	KRU 3S- 3G	26,550	8	3000	65000	0.375			2003
Kuparuk River	CP	FL-Produced H2O	KRU 2A- CPF 2	24,927	10		55000	0.438			1998
Kuparuk River	CP	FL-Produced H2O	KRU 3K- CPF 3	23,466	8	3000	65000	0.375			1986
Prudhoe Bay	BPXA	FL-Produced H2O	PBU DS 13- FS 1	22,732	14						
Kuparuk River	CP	FL-Produced H2O	KRU 3N- CFP 3	22,618	8	3000	65000	0.375			1986
Milne Point	BPXA	FL-Produced H2O	MPU S- E	22,605	8						
Prudhoe Bay	BPXA	FL-Produced H2O	GC 2-PBU Y	21,308	12						
Kuparuk River	CP	FL-Produced H2O	KRU 2X- CPF 2	20,534	10		55000	0.438			1985
Colville River, Alpine	CP	FL-Produced H2O	AU CD2- AU PF	20,520	8		35000	0.812			
Prudhoe Bay	BPXA	FL-Produced H2O	GC1- GC 2	19,833	28						

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Kuparuk River	CP	FL-Produced H2O	4Corners-CPF 2	19,300	10	3000		0.438			1986
Endicott	BPXA	FL-Produced H2O	EU SDI- MPI	18,648	14	3600	65000	0.562			1987
Kuparuk River	CP	FL-Produced H2O	KRU 1Y-CPF1	18,071	12	3000	65000	0.5			1985
Kuparuk River	CP	FL-Produced H2O	KRU 1H- 1B	17,970	8.625		55000	0.438			1991
Kuparuk River	CP	FL-Produced H2O	KRU 2N- 2L	17,772	12	3000	65000	0.562			1998
Kuparuk River	CP	FL-Produced H2O	KRU 1F-CPF 1	17,738	10.75		55000	0.438			1984
Prudhoe Bay	BPXA	FL-Produced H2O	PBU X- GC 3	17,605	6			0.375			
Prudhoe Bay	BPXA	FL-Produced H2O	PBU X- GC 3	17,563	6			0.375			
Colville River, Alpine	CP	FL-Produced H2O	AU CD4- AU PF	17,500	10		65000	0.532			
Prudhoe Bay	BPXA	FL-Produced H2O	PBU E- GC 1Rt1	17,424	6						
Prudhoe Bay	BPXA	FL-Produced H2O	PBU M-GC 2	17,210	20						
Milne Point	BPXA	FL-Produced H2O	MPU C-MPU CFP	17,193	8				794	1	
Kuparuk River	CP	FL-Produced H2O	KRU 1D-CPF 1	16,931	12.75	3000	65000	0.562			2005
Prudhoe Bay	BPXA	FL-Produced H2O	PBU DS 9-FS 2	16,837	16						
Kuparuk River	CP	FL-Produced H2O	KRU 2M- 4 Corners	16,751	8	3000	65000	0.375			1993
Prudhoe Bay	BPXA	FL-Produced H2O	PBU S- M	16,607	14						
Kuparuk River	CP	FL-Produced H2O	KRU 1D-CPF 1	16,438	12.75	3000	65000	0.562			2005
Kuparuk River	CP	FL-Produced H2O	KRU 2V-CPF 2	16,404	12	3000	65000	0.5			1985
Kuparuk River	CP	FL-Produced H2O	KRU 2K- 2H	16,292	8	3000	65000	0.375			1989
Prudhoe Bay	BPXA	FL-Produced H2O	PBU R- GC 2	16,029	12			0.375			
Prudhoe Bay	BPXA	FL-Produced H2O	LPC-SIP	15,716	18			0.375			
Prudhoe Bay	BPXA	FL-Produced H2O	PBU DS 3-FS 2	15,556	16	2900	56000	0.375			1983
Kuparuk River	CP	FL-Produced H2O	KRU 2G-CPF 2	15,343	6.625	3200	65000	0.5			2005
Kuparuk River	CP	FL-Produced H2O	KRU 3I TI-CPF 3	15,039	13	4400	65000	0.688			1996
Kuparuk River	CP	FL-Produced H2O	KRU 2T- 2A	14,996	10	3200	65000	0.5			2007
Prudhoe Bay	BPXA	FL-Produced H2O	PBU P- Y	14,731	10	3600	65000	0.5			1989
Kuparuk River	CP	FL-Produced H2O	KRU 2E- 2D	14,472	8	3000	65000	0.375			1985

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Prudhoe Bay	BPXA	FL-Produced H2O	PBU A- GC 3	13,362	6						
Prudhoe Bay	BPXA	FL-Produced H2O	PBU A- GC 3	13,361	6						
Prudhoe Bay	BPXA	FL-Produced H2O	PBU A- GC3	13,361	6						
Prudhoe Bay	BPXA	FL-Produced H2O	PBU A- GC3	13,348	6						
Kuparuk River	CP	FL-Produced H2O	KRU 3F- 3B	13,010	10		55000	0.438			1990
Prudhoe Bay	BPXA	FL-Produced H2O	GC3- GC1	12,934	20						
Kuparuk River	CP	FL-Produced H2O	KRU 2U TI- 2V	12,931	12	3000	65000	0.5			1985
Kuparuk River	CP	FL-Produced H2O	KRU 1C- CPF 1	12,520	10.75	3000	65000	0.5			2001
Kuparuk River	CP	FL-Produced H2O	KRU 3I- 3A	12,305	8	3000	65000	0.375			1986
Kuparuk River	CP	FL-Produced H2O	KRU 2K- 2H	12,280	6	3000	65000	0.312			1989
Kuparuk River	CP	FL-Produced H2O	KRU 1A- CPF 1	11,717	16	3000	65000	0.625	385, 1051	2	1983
Kuparuk River	CP	FL-Produced H2O	KRU 3C- CPF 3	11,434	8	3000	65000	0.375			1985
Kuparuk River	CP	FL-Produced H2O	KRU 3G- 3F	11,301	8	3000	65000	0.375			1990
Kuparuk River	CP	FL-Produced H2O	KRU 2B- CPF 2	11,162	10.75		55000	0.438			1985
Prudhoe Bay	BPXA	FL-Produced H2O	PBU PM2- WDSP	11,138	18			0.375			
Kuparuk River	CP	FL-Produced H2O	KRU 2W- 2U	10,951	10		55000	0.438			1985
Kuparuk River	CP	FL-Produced H2O	KRU 3H- 3A	10,940	6	3000	65000	0.312			1987
Kuparuk River	CP	FL-Produced H2O	KRU 1R- 1G	10,658	6.625	3000	65000	0.312			1984
Kuparuk River	CP	FL-Produced H2O	KRU 2E- 2D	10,565	6	3000	65000	0.312			1985
Kuparuk River	CP	FL-Produced H2O	KRU 1L- 1F	10,553	8.625	3000	65000	0.375	393	1	1984
Kuparuk River	CP	FL-Produced H2O	KRU 3Q- 3O TI	10,355	10		55000	0.438			1987
Kuparuk River	CP	FL-Produced H2O	KRU 2F- CPF 2	10,054	8	3000	65000	0.375			1984
Kuparuk River	CP	FL-Produced H2O	KRU 3M- 3I	9,802	8	4400	65000	0.5			1996
Kuparuk River	CP	FL-Produced H2O	KRU 3B- CPF 3	9,595	12	3000	65000	0.5			1990
Kuparuk River	CP	FL-Produced H2O	KRU 3R- 3Q	9,375	8	3000	65000	0.375			1987
Kuparuk River	CP	FL-Produced H2O	KRU 1E- (behind) CPF 1	9,059	8.625	3000	65000	0.322			1982
Prudhoe Bay	BPXA	FL-Produced H2O		8,751	16			0.375			

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Kuparuk River	CP	FL-Produced H2O	KRU 3J-CPF 3	7,760	8	3000	65000	0.375			1985
Prudhoe Bay	BPXA	FL-Produced H2O	PBU DS 14-FS 3	7,588	12			0.312			
Prudhoe Bay	BPXA	FL-Produced H2O	PBU DS 4-FS 2	7,087	16						
Prudhoe Bay	BPXA	FL-Produced H2O	PBU B- GC 3	6,962	6						
Prudhoe Bay	BPXA	FL-Produced H2O	PBU B- GC 3	6,936	6						
Kuparuk River	CP	FL-Produced H2O	KRU 2A-4Corners	6,187	8	3000	65000	0.375			1993
Kuparuk River	CP	FL-Produced H2O	KRU 1B-CPF 1	4,071	10.75	3000	65000	0.395	372	1	1982
Kuparuk River	CP	FL-Produced H2O	KRU 3Q-3O TI	2,810	10		55000	0.438			1987
Kuparuk River	CP	FL-Produced H2O	KRU 3O-3N TI	2,791	10		55000	0.438			1987
Kuparuk River	CP	FL-Produced H2O	KRU 3I TI-CPF 3	2,386	10.75		55000	0.438			1985
Prudhoe Bay	BPXA	FL-Produced H2O	PBU W-EWE JCT	1,626	8						
Prudhoe Bay	BPXA	FL-Produced H2O	PBU U-Jct	757	12						
Colville River, Alpine	CP	FL-Produced H2O		645	8		65000	0.375			
Kuparuk River	CP	FL-Produced H2O		614	12.75	3000	65000	0.562			2005
Prudhoe Bay	BPXA	FL-Produced H2O		532	6						
Milne Point	BPXA	FL-Produced H2O		380	6			0.375			
Prudhoe Bay	BPXA	FL-Produced H2O		332	8			0.375			
Milne Point	BPXA	FL-Produced H2O		257	8			0.375			
Kuparuk River	CP	FL-Produced H2O	KRU 1D-CPF 1	237	8.625	3000	65000	0.5			2006
Milne Point	BPXA	FL-Produced H2O		210	6			0.375			
Milne Point	BPXA	FL-Produced H2O		210	6						
Prudhoe Bay	BPXA	FL-Produced H2O		181	6						
Milne Point	BPXA	FL-Produced H2O		180	6						
Prudhoe Bay	BPXA	FL-Produced H2O		162	8						
Kuparuk River	CP	FL-Produced H2O		120	8.625	3000	65000	0.5			1998
Kuparuk River	CP	FL-Produced H2O	KRU 3I TI-CPF 3	10	10.75	3200	65000	0.5			2009
Kuparuk River	CP	FL-3 phase	KRU 2P-CPF 2	113,539	24		55000	0.469			2001

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Prudhoe Bay	BPXA	FL-3 phase	GC 1- PBU PM 2	51,223	36	650	55000	0.375			1984
Kuparuk River	CP	FL-3 phase	KRU 2L- 2M	39,494	16	740	65000	0.312			1998
Prudhoe Bay	BPXA	FL-3 phase	PBU L/V TI- EWE Jct	36,377	24	740	65000	0.344			2001
Prudhoe Bay	BPXA	FL-3 phase	EWE jct- GC 2	33,764	30	675	65000	0.562			1994
Prudhoe Bay	BPXA	FL-3 phase	PBU Y- GC 1	33,520	24	675	55000	0.375	332, 320	2	1983
Milne Point	BPXA	FL-3 phase	MPU J-TR 14 TI	32,500	10				334	1	1982
Prudhoe Bay	BPXA	FL-3 phase	PBU S- GC 2	32,397	24	675	55000	0.375/0.5			1983
Colville River, Alpine	CP	FL-3 phase	AU CD 3- AU PF	27,790	16		35000	0.281			
Prudhoe Bay	BPXA	FL-3 phase	Heald Point Niakuk- PBU L3 Intersection	26,795	18		65000	0.312			
Kuparuk River	CP	FL-3 phase	KRU 3S- 3G	26,550	16	740	65000	0.312			2003
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 16- FS 2	26,478	16	1440	65000	0.312	234, 176	2	1980
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 16- FS 2	26,448	16		65000	0.312			
Colville River, Alpine	CP	FL-3 phase	AU CD4- AU PF	23,500	14		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU L1- WSPD	23,151	24		65000	0.250/0.375			
Prudhoe Bay	BPXA	FL-3 phase	GC 3- FS 3	22,644	24	3600	65000	1			1983
Prudhoe Bay	BPXA	FL-3 phase	PBU K- CG 1	22,462	24	675	55000	0.375			1984
Milne Point	BPXA	FL-3 phase	MPU F-L-C Intersection	22,188	14		65000	0.312			
Prudhoe Bay	BPXA	FL-3 phase	FS 1- FS 3	22,165	24	1440	65000	0.5			1994
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 13- FS 1	21,841	12		56000	0.406			
Kuparuk River	CP	FL-3 phase	KRU 1H- CPF 1	20,263	12.75	1480	65000	0.375			1981
Kuparuk River	CP	FL-3 phase	KRU 1R- 1A	19,507	16	740	65000	0.312			1986
Kuparuk River	CP	FL-3 phase	4Corners- CPF 2	19,467	24	740		0.469			1997
Kuparuk River	CP	FL-3 phase	4Corners- CPF 2	19,234	24	740	65000	0.375			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU L5-PBU L3 Jct	19,147	18		65000	0.312			
Endicott	BPXA	FL-3 phase	EU SDI- MPI	18,715	28	740		0.312			1987

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 18-FS 1	18,698	16		65000	0.312			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 18-FS 1	18,676	12		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 15-FS 3	18,541	12		65000	0.375	338	1	
Prudhoe Bay	BPXA	FL-3 phase	PBU L1-PBU L2	18,539	24		65000	0.469			
Prudhoe Bay	BPXA	FL-3 phase	PBU 15-FS 3	18,529	16		65000	0.312	1087	1	1982
Kuparuk River	CP	FL-3 phase	KRU 1D-CPF 1	17,969	14	1415	65000	0.375			1982
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 12-FS 1	17,900	16		56000	0.344			
Kuparuk River	CP	FL-3 phase	KRU 1F-CPF 1	17,859	18	1000	65000	0.375			1983
Milne Point	BPXA	FL-3 phase	MPU S- S/K TI	17,838	12		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 12-FS 1	17,836	24		65000	0.281			
Prudhoe Bay	BPXA	FL-3 phase	PBU X- GC 3	17,776	24	675	55000	0.0375			1983
Milne Point	BPXA	FL-3 phase	MPU K- S/K TI	17,737	8		65000	0.312			
Prudhoe Bay	BPXA	FL-3 phase	PBU Z-EWE JCT	17,672	24	675	65000	281	340, 296	2	1994
Colville River, Alpine	CP	FL-3 phase	AU CD2- AU PF	17,600	20	1350	65000	0.322			
Prudhoe Bay	BPXA	FL-3 phase	PBU E- GC 1Rt1	17,523	10		65000	0.562			
Prudhoe Bay	BPXA	FL-3 phase	PBU E- GC 1Rt1	17,376	6		55000	0.375			
Kuparuk River	CP	FL-3 phase	KRU 1D-CPF 1	17,364	24		55000	0.469			2005
Prudhoe Bay	BPXA	FL-3 phase	PBU E- GC 1Rt1	17,347	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU E- GC 1Rt1	17,316	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU E- GC 1Rt1	17,301	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU E- GC 1Rt1	17,297	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU M-GC 2	17,068	24		52000	0.375	266	1	1990
Kuparuk River	CP	FL-3 phase	KRU 2M-4Corners	16,594	24	740		0.469			2001
Prudhoe Bay	BPXA	FL-3 phase	PBU L3 Jct-LPC	16,437	24	900	65000	0.312	174	1	1985
Kuparuk River	CP	FL-3 phase	KRU 1J- 1D	16,435	24		55000	0.469			2005
Prudhoe Bay	BPXA	FL-3 phase	PBU L3 Jct-LPC	16,432	18		65000	0.312			
Kuparuk River	CP	FL-3 phase	KRU 2N- 2L	16,328	16	740	65000	0.312			1998

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 9-FS 2	16,153	24		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 9-FS 2	16,146	16	792	56000	0.344			
Milne Point	BPXA	FL-3 phase	MPU C-MPU CFP	16,088	24		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 9-FS 2	16,070	24	708	65000	0.375	193	1	1979
Kuparuk River	CP	FL-3 phase	KRU 2V-CPF 2	15,996	24	740	65000	0.375			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU R- GC 2	15,876	24		55000	0.375			
Kuparuk River	CP	FL-3 phase	KRU 1C-CPF 1	15,745	14	740	65000	0.375			1981
Prudhoe Bay	BPXA	FL-3 phase	PBU E- GC 1Rt1	15,382	24		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU E- GC 1Rt1	15,334	16		65000	0.375			
Kuparuk River	CP	FL-3 phase	KRU 3I TI-CPF 3	15,194	24	740	65000	0.375			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 3-FS 2	14,995	24	708		0.281			1994
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 3-FS 2	14,930	16	850	56000	0.344	1182	1	1979
Kuparuk River	CP	FL-3 phase	KRU 2G-CPF 2	14,670	10	740	65000	0.365			1984
Prudhoe Bay	BPXA	FL-3 phase	PBU L4-PBU L3 Jct	14,537	18		65000	0.312			
Kuparuk River	CP	FL-3 phase	KRU 2D- 2C	14,495	14	740	65000	0.375	1126	1	1984
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 15-DS 7	14,186	24		65000	0.281			
Prudhoe Bay	BPXA	FL-3 phase	PBU A- GC3	13,889	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU A- GC3	13,862	10		65000	0.562			
Kuparuk River	CP	FL-3 phase	KRU 2Z- 2X	13,629	10		55000	0.438	1180	1	1984
Prudhoe Bay	BPXA	FL-3 phase	PBU P- Y	13,616	18		55000	0.281			
Prudhoe Bay	BPXA	FL-3 phase	PBU A- GC3	13,492	24		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU L- PBU V	13,269	24		65000	0.344			
Prudhoe Bay	BPXA	FL-3 phase	PBU F- GC 1	13,177	24		55000	0.375			
Kuparuk River	CP	FL-3 phase	KRU 2K- 2H	12,884	12.75	740	65000	0.312			1989
Prudhoe Bay	BPXA	FL-3 phase	GC3- GC1	12,786	24		65000	0.5			
Kuparuk River	CP	FL-3 phase	KRU 3F- 3B	12,695	20	740	65000	0.406			1990
Kuparuk River	CP	FL-3 phase	KRU 3O-3N TI	12,550	24	740	65000	0.375			1986

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Prudhoe Bay	BPXA	FL-3 phase	PBU F- GC 1	12,306	10		55000	0.5			
Prudhoe Bay	BPXA	FL-3 phase	PBU F- GC 1	12,170	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU F- GC 1	12,161	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU F- GC 1	12,154	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU F- GC 1	12,144	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU F- GC 1	12,143	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU F- GC 1	12,139	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU F- GC 1	12,134	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU PM2-WDSP	11,522	24		65000	0.250/0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 13-DS 6	11,449	24	500	65000	0.281	1220, 298	2	1983
Kuparuk River	CP	FL-3 phase	KRU 1Q- TI	11,347	16	740	65000	0.312			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU-U-GC 2	11,147	16		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 6-FS 3	11,052	12	1440	56000	0.281			1977
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 6-FS 3	11,050	12	1440	56000	0.406			1979
Kuparuk River	CP	FL-3 phase	KRU 3G- 3F	11,045	16	740	65000	0.312			1990
Kuparuk River	CP	FL-3 phase	KRU 1Y- 1A	11,000	20	740	65000	0.406			1982
Kuparuk River	CP	FL-3 phase	KRU 1A-CPF 1	10,983	14	1415	65000	0.375	324	1	1982
Kuparuk River	CP	FL-3 phase	KRU 1G- 1A	10,978	16	740	65000	0.406			1982
Kuparuk River	CP	FL-3 phase	KRU 1L- 1F	10,840	12.75	740	65000	0.312			1990
Kuparuk River	CP	FL-3 phase	KRU 1Q TI-CPF 1	10,751	20	740	65000	0.406			1983
Kuparuk River	CP	FL-3 phase	KRU 2B-CPF 2	10,749	12.75	740	65000	0.375			1984
Kuparuk River	CP	FL-3 phase	KRU 2X- TI	10,723	18	740	65000	0.375	256	1	1985
Kuparuk River	CP	FL-3 phase	KRU 2E- 2D	10,535	10.75	740	65000	0.279			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 6-FS 3	10,412	24		65000	0.281			
Kuparuk River	CP	FL-3 phase	KRU 1A-CPF 1	10,266	24	740	65000	0.375	203	2	1987
Kuparuk River	CP	FL-3 phase	KRU 2T- 2A	10,259	12.75	740	65000	0.312			1986
Kuparuk River	CP	FL-3 phase	KRU 2U TI- 2V	10,242	24	740	65000	0.375	231, 331	2	1985

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Kuparuk River	CP	FL-3 phase	KRU 3H- 3A	9,912	18	740	65000	0.312			1987
Prudhoe Bay	BPXA	FL-3 phase	PBU West Beach- L1	9,804	6		65000	0.432			
Kuparuk River	CP	FL-3 phase	KRU 3M- 3I	9,803	12	740	65000	0.312			1987
Kuparuk River	CP	FL-3 phase	KRU 3I- 3A	9,775	18	740	65000	0.375			1986
Kuparuk River	CP	FL-3 phase	KRU 2F- CPF 2	9,754	12.75	740	65000	0.375			1984
Kuparuk River	CP	FL-3 phase	KRU 1E- CPF 1	9,672	14	1415	65000	0.375			1982
Kuparuk River	CP	FL-3 phase	KRU 3N TI- 3C TI	9,645	24	740	65000	0.375			1986
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 2- FS 1	9,642	16		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU West Beach- L1	9,605	12		65000	0.625			
Kuparuk River	CP	FL-3 phase	KRU 2X- CPF 2	9,527	18	740	65000	0.375			1985
Kuparuk River	CP	FL-3 phase	KRU 3B- CPF 3	9,466	24	740	65000	0.375	1083	1	1990
Prudhoe Bay	BPXA	FL-3 phase	PBU PM1- WDSP	9,083	18		65000	0.25			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 2- FS 1	8,951	24		65000	0.281			
Prudhoe Bay	BPXA	FL-3 phase	PBU N- GC 2	8,821	6		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU N- GC 2	8,819	6		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	8,762	24		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 2- FS 1	8,714	12		56000	0.406			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 2- FS 1	8,685	12		56000	0.406			
Kuparuk River	CP	FL-3 phase	KRU 2H- 4Corners	8,545	12	740	65000	0.312			1984
Prudhoe Bay	BPXA	FL-3 phase	PBU G- GC 1	8,501	16		65000	0.375			
Kuparuk River	CP	FL-3 phase	KRU “Y”- TI	8,453	16	740	65000	0.406			1982
Kuparuk River	CP	FL-3 phase	KRU 2W- 2U	8,429	16	740	65000	0.312			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU J- GC 2	8,421	24		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU J- GC 2	8,383	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU N- GC 2	8,374	24		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU J- GC 2	8,371	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU J- GC 2	8,361	6		55000	0.375			

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Prudhoe Bay	BPXA	FL-3 phase	PBU J- GC 2	8,358	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU J- GC 2	8,356	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU J- GC 2	8,355	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU J- GC 2	8,347	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU J- GC 2	8,229	10		65000	0.307			
Prudhoe Bay	BPXA	FL-3 phase	PBU K- E	7,996	10		65000	0.5			
Prudhoe Bay	BPXA	FL-3 phase	PBU G- GC 1	7,942	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU G- GC 1	7,939	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU G- GC 1	7,935	6		55000	0.375			
Kuparuk River	CP	FL-3 phase	KRU 3N- TI	7,856	12.75	740	65000	0.312			1986
Kuparuk River	CP	FL-3 phase	KRU 3J- CPF 3	7,785	12	740	65000	0.312	277	1	1985
Prudhoe Bay	BPXA	FL-3 phase	PBU G- GC 1	7,785	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU G- GC 1	7,780	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU D- GC 1	7,692	24		55000	0.374			
Milne Point	BPXA	FL-3 phase	MPU B- CFP	7,645	14		65000	0,312			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 4- FS 2	7,620	12	1440	56000	0.406			1984
Prudhoe Bay	BPXA	FL-3 phase	PBU B- GC 3	7,605	24	675	55000	0.375	674	1	1984
Prudhoe Bay	BPXA	FL-3 phase	PBU L2- LPC	7,580	14		65000	0.281			
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	7,481	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	7,423	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 4- FS 2	7,413	24		65000	0.281			
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	7,389	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	7,231	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	7,226	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	7,211	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS1- FS 1	7,189	20		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	7,184	6		55000	0.375			

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Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	7,178	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	7,174	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS1- FS 1	7,130	12		56000	0.406			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS1- FS 1	7,124	16		56000	0.344			
Prudhoe Bay	BPXA	FL-3 phase	PBU L2- LPC	7,088	24	900	65000	0.469	369	1	1986
Kuparuk River	CP	FL-3 phase	KRU 3QTI- 3O TI	6,991	18	740	65000	0.312			1986
Milne Point	BPXA	FL-3 phase	S/K TI- MPU E	6,894	14						
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 14- FS 3	6,784	12		56000	0.406			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 14- FS 3	6,775	24	500	65000	0.281	1125	1	1984
Kuparuk River	CP	FL-3 phase	KRU 3C- TI	6,455	16	740	65000	0.312			1985
Kuparuk River	CP	FL-3 phase	KRU 2C- CPF 2	6,250	16	740	65000	0.406			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 5- FS 1	6,060	12		56000	0.406			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 5- FS 1	6,044	12		56000	0.406			
Kuparuk River	CP	FL-3 phase	KRU 3R- 3Q TI	6,036	14	740	65000	0.281			1988
Kuparuk River	CP	FL-3 phase	KRU 3N- TI	6,018	16	740	65000	0.312			1986
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 5- FS 1	5,879	8		56000	0.438			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,661	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,641	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,635	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,609	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,593	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,545	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,532	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,528	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,528	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,509	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU B- GC 3	5,507	6		55000	0.375			

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Prudhoe Bay	BPXA	FL-3 phase	PBU B- GC 3	5,490	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU B- GC 3	5,481	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU B- GC 3	5,466	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,456	6	3600	55000	0.375	381	1	1985
Prudhoe Bay	BPXA	FL-3 phase	PBU B- GC 3	5,443	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,403	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU D- GC 1	5,397	6	3600	55000	0.375	857	1	1978
Milne Point	BPXA	FL-3 phase	Tract 14	5,397	14						
Prudhoe Bay	BPXA	FL-3 phase	PBU D- GC 1	5,388	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,372	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU D- GC 1	5,372	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU D- GC 1	5,370	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU D- GC 1	5,363	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU D- GC 1	5,363	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,361	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,360	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU D- GC 1	5,358	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,357	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,351	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 7- FS 3	5,310	12		56000	0.281			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 7- FS 3	5,273	12		65000	0.281			
Prudhoe Bay	BPXA	FL-3 phase	PBU C- GC 3	5,224	24		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU B- GC 3	5,147	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU B- GC 3	5,144	6		55000	0.375	1181	1	1981
Prudhoe Bay	BPXA	FL-3 phase	PBU B- GC 3	5,130	6		55000	0.375			
Kuparuk River	CP	FL-3 phase	KRU 3C TI- CPF 3	5,000	24	740	65000	0.375			1986
Prudhoe Bay	BPXA	FL-3 phase	PBU D- GC 1	4,894	6		55000	0.375			

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Prudhoe Bay	BPXA	FL-3 phase	PBU W-EWE JCT	4,496	24		6000	0.281			
Kuparuk River	CP	FL-3 phase	KRU 2A-4Corners	4,350	18	740	65000	0.406			1996
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 7-FS 3	4,215	24		65000	0.406			
Kuparuk River	CP	FL-3 phase	KRU 1B-CPF 1	4,092	12.75	1415	65000	0.33			1982
Kuparuk River	CP	FL-3 phase	KRU 1B-CPF 1	4,013	6.625	1415	65000	0.25			1982
Prudhoe Bay	BPXA	FL-3 phase	PBU L2- LPC	3,680	12		65000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU G- TI	3,669	14		55000	0.562			
Kuparuk River	CP	FL-3 phase	KRU 3Q-3O TI	3,296	12.75	740	65000	0.312			1986
Kuparuk River	CP	FL-3 phase	KRU 1Q- TI	3,066	16	740	65000	0.406			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 6-FS 3	3,001	16		65000	0.375			
Kuparuk River	CP	FL-3 phase	KRU 3O- TI	2,773	10	740	65000	0.279			1986
Kuparuk River	CP	FL-3 phase	KRU 3A- TI	2,606	12.75	740	65000	0.375			1986
Kuparuk River	CP	FL-3 phase	KRU 2U- TI	2,592	16	740	65000	0.312			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 11-FS 2	2,436	16		65000	0.312			
Prudhoe Bay	BPXA	FL-3 phase	PBU Q- GC 2	2,409	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU Q- GC 2	2,401	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU Q- GC 2	2,399	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU Q- GC 2	2,395	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU Q- GC 2	2,393	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU Q- GC 2	2,386	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU Q- GC 2	2,383	6		55000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 11-FS 2	2,300	24		65000	0.25			
Kuparuk River	CP	FL-3 phase	KRU 1R- 1A	2,244	16	740	65000	0.375			2008
Milne Point	BPXA	FL-3 phase	MPU E-CFP	2,180	14		65000	0.312			
Kuparuk River	CP	FL-3 phase		1,836	12.75	740	65000	0.375			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU L2- TI	1,649	12		65000	0.625			
Kuparuk River	CP	FL-3 phase	KRU 2L- TI	1,479	16	740	65000	0.312			1998

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Kuparuk River	CP	FL-3 phase	KRU 1Y- 1A	1,271	16	740	65000	0.406			1982
Kuparuk River	CP	FL-3 phase	KRU 3A- TI	1,225	12	740	65000	0.375			1985
Kuparuk River	CP	FL-3 phase	KRU 3A- 3I TI	1,143	24	740	65000	0.375			1985
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 18- TI	1,090	12		65000	0.625			
Prudhoe Bay	BPXA	FL-3 phase		918	24		56000	0.375			
Prudhoe Bay	BPXA	FL-3 phase	PBU DS 6- FS 3	736	24		65000	0.281			
Milne Point	BPXA	FL-3 phase	MPU C-MPU CFP	534	14		65000	0.312			
Prudhoe Bay	BPXA	FL-3 phase		500	12		56000	0.406			
Milne Point	BPXA	FL-3 phase		380	6						
Prudhoe Bay	BPXA	FL-3 phase	PBU H- GC 2	375	12						
Kuparuk River	CP	FL-3 phase	KRU 1R- 1A	373	16	740	65000	0.312			2008
Milne Point	BPXA	FL-3 phase		348	8						
Milne Point	BPXA	FL-3 phase	MPU B- CFP	235	14		65000	0.312			
Milne Point	BPXA	FL-3 phase		210	6						
Milne Point	BPXA	FL-3 phase		210	6						
Prudhoe Bay	BPXA	FL-3 phase	PBU V-TI	195	16		65000	0.469			
Milne Point	BPXA	FL-3 phase		180	6						
Kuparuk River	CP	FL-3 phase		150	16	740	65000	0.312			1985
Kuparuk River	CP	FL-3 phase	KRU 1Y- TI	148	20	675	65000	0.5			1994
Kuparuk River	CP	FL-3 phase	KRU 1Y- 1A	140	20	675	65000	0.406			1994
Kuparuk River	CP	FL-3 phase		140	12	740	65000	0.312			1985
Kuparuk River	CP	FL-3 phase		140	16	740	65000	0.312			1985
Kuparuk River	CP	FL-3 phase		114	13	740	65000	0.312			1984
Prudhoe Bay	BPXA	FL-3 phase		100	14		65000	0.281			
Kuparuk River	CP	FL-3 phase		92	16	740	65000	0.406			1983
Kuparuk River	CP	FL-3 phase		83	12.75	740	65000	0.312			1986
Prudhoe Bay	BPXA	FL-3 phase		79	12		56000	0.406			

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thickness	Spill Case #	# of Spills	Year in Service
Kuparuk River	CP	FL-3 phase		72	24	740	65000	0.375			1998
Kuparuk River	CP	FL-3 phase		69	13	740	65000	0.375			1984
Kuparuk River	CP	FL-3 phase		68	18	1000	65000	0.375			1982
Prudhoe Bay	BPXA	FL-3 phase		50	14		65000	0.281			
Kuparuk River	CP	FL-3 phase		48	12.75	740	65000	0.312			1984
Kuparuk River	CP	FL-3 phase		36	12.75	740	65000	0.312			1984
Prudhoe Bay	BPXA	FL-3 phase		29	14						
Kuparuk River	CP	FL-3 phase		17	10		55000	0.438			2008
Kuparuk River	CP	FL-3 phase	KRU 1Y- 1A	13	16	740	65000	0.312			1982
Kuparuk River	CP	FL-3 phase	KRU 1Q- TI	10	20	740	65000	0.406			1983
		N=378	Total=	4,214,434					Count=	36	170

C.2 Oil Transmission Pipelines

Oil Field	Operator	ADEC REG CAT	Pipeline Route	Hydraulic Length (ft)	Pipeline Diameter	Design Pressure	Yield Strength	Nominal Wall Thick-ness	Spill Case #	# of Spills	Year in Service
Colville River, Alpine	CP	OTP	AU- KRU 2	180,576	14		65000	0.312	273	1	2000
Kuparuk River	CP	OTP	KRU-PS1	147,600	24	1415		0.500	367	1	
Endicott	BPXA	OTP	EU-Skid 50	139,418	16		65000	0.312			
Badami	BPXA	OTP	BU-EU TI	132,327	12		65000	0.281 0.500			
Northstar	BPXA	OTP	NSU-PS1	92,379	10			0.307 0.279 0.594			
Milne Point	BPXA	OTP	MPU-KRU-TI	56,897	14		65000	0.312			
Kuparuk River	CP	OTP	KRU Extension	48,271	12.75	1415		0.406	376	1	1985
Prudhoe Bay	BPXA	OTP	LPC-PS 1	32,317	16	550	65000	0.342			
Prudhoe Bay	BPXA	OTP	FS 1- Skid 50	29,301	18			0.344			
Prudhoe Bay	BPXA	OTP	GC 1- Skid 50	25,683	28	740	65000	0.312 0.688			
Prudhoe Bay	BPXA	OTP	GC 2-GC 1	18,781	24	740	52000	0.375	129	1	1993
Prudhoe Bay	BPXA	OTP	FS 1- FS 2	16,729	12	740	65000	0.375	254	1	
Prudhoe Bay	BPXA	OTP	GC 2-GC 1	16,326	34	740	52000	0.375	268	1	1977
Prudhoe Bay	BPXA	OTP	COTU- TI	4,995	6	740	65000	0.432			
Prudhoe Bay	BPXA	OTP	Skid 50-PS1	1,321	34	740	52000	0.344	188	1	2006
Prudhoe Bay	BPXA	OTP	Skid 50-PS1	790	28						
		N=16	Total=	**943,712**					Count=	7	**5**

Note: Two spill cases could not be assigned to an oil transmission pipeline

APPENDIX D

D.1 Summary of Alaska North Slope Loss-of-Integrity Spills Greater Than 10,000 Gallons (7/1/95 through 12/31/09).

Size (Gallons)	Date	Oil Field	Regulatory Category	Cause	Leak Detection	Investigation	Mitigation Measures
241,038	12/19/06	Prudhoe Bay	Above Ground Storage Tank	The cause for this spill has been determined to be a mechanical failure involving the agitation jets used to suspend solids near the bottom of the tank. Misalignment of jets caused a hole to erode through the bottom of the tank.	There was no information provided that may have determined how the leak was detected.	There was no information on the investigation of the spill.	There were no mitigation measures that were mentioned in the report.
212,252	3/2/06	Prudhoe Bay	Oil Transmission Pipeline	The cause of this incident has been determined to be due to corrosion/internal corrosion. The source was a ¼ inch hole at the 6 o'clock position.	The leaked was detected by odor.	A joint industry/ agency investigation was conducted and a 31-page report published.	The corroded area of the pipe was permanently welded/sleeved. No other mitigation measures were mentioned in the report.
94,920	12/25/08	Kuparuk River	Facility Oil Piping.	The cause of this incident has been determined to be due to corrosion/internal corrosion of the 6-inch water injection well line.	Workers witnessed an anomaly in the drill site 1L surveillance system, investigated the source and discovered the spill.	There was no information on the investigation of the spill.	The damaged section of the pipe was removed and replaced. No additional mitigation measures were mentioned.

Size (Gallons)	Date	Oil Field	Regulatory Category	Cause	Leak Detection	Investigation	Mitigation Measures
92,400	4/15/01	Kuparuk River	Flowline	This spill was caused by external corrosion at or near weld joints.	The leaked was detected visually.	This investigation was completed using Event and Causal Factor Charting - CPAI Incident Investigation Report	Authorities identified mitigation measures that may help prevent another spill under these circumstances. First, the piping should be replaced with new piping that incorporates the appropriate technology for below grade piping. The frequency of inspection of potential corrosion areas of below grade piping should be increased. Information from the investigation concerning the cause of this spill should be applied to future inspections. Potential corrosion areas of piping should be replaced with the most up-to-date piping before the integrity of the pipeline is lost. Low discharge pressure shutdowns on the water systems should be installed at Central Processing Facilities 1, 2 and 3.
63,000	1/10/98	Kuparuk River	Flowline	This spill was the result of material failure of the pipe or weld.	There was no information provided that may have determined how the leak was detected.	There was no information on the investigation of the spill.	It was decided that any preventative measures that could be taken in the future would be agreed upon after reviewing the results of the failure analysis performed on the pipe.

Size (Gallons)	Date	Oil Field	Regulatory Category	Cause	Leak Detection	Investigation	Mitigation Measures
61,626	11/3/08	Prudhoe Bay	Facility Oil Piping	The pipeline rupture was determined to be due to corrosion/internal corrosion.	The leaked was detected visually.	This spill was investigated using the Comprehensive List of Cause	As part of the mitigation measures to be taken, BPXA recommended that pipelines undergo a thorough assessment prior to restart when the cause of shutdown is not associated with a small issue that has been mitigated or repair. If this were the case, containment loss due to loss of integrity would fall into this category. Evaluate all current production processes to ensure that the appropriate mitigation measures have been identified for areas of potential risk. Also, similar areas of high-corrosion risk along facility oil piping should be identified and inspected for the same loss of integrity.

Size (Gallons)	Date	Oil Field	Regulatory Category	Cause	Leak Detection	Investigation	Mitigation Measures
51,198	3/26/05	Kuparuk River	Well	The cause of this incident has been determined to be due to corrosion/internal corrosion from a 6-inch water injection line.	There was no information provided that may have determined how the leak was detected.	There was no information on the investigation of the spill.	To prevent a failure similar to this occurrence, the current internal inspection program should be evaluated and modified as part of Technical Root Cause Failure Analysis. "As part of a RCFA evaluate and implement modifications to the existing mitigation (chemicals) and monitoring (probes, coupons) program that would minimize the possibility of reoccurrence of this type of failure." Also as part of the RCFA, the current pigging program should be reviewed and modified. The leak detection systems that are currently in place for cross country pipelines should be reviewed and modified. Also, identify any additional requirements needed to bring the 2K water injection line back into service.
46,000	11/29/09	Prudhoe Bay	Flowline	The primary cause of this spill was determined to be thermal expansion and overpressure. The rupture was approximately 24-inches long, located at the bottom of the pipe.	The leaked was detected visually.	BP investigated the spill using the Comprehensive List of Cause. A separate investigation was being conducted by the agencies.	No mitigation measures were identified in the record. The line was shut-in but repairs and the restart of the line was not mentioned in the report.
38,600	4/2/07	Milne Point	Facility Oil Piping	It was determined that this spill was due to a valve or seal failure within the facility oil piping.	There was no information provided that may have determined how the leak was detected.	There was no information on the investigation of the spill.	There were no mitigation measures that were mentioned in the report.

Size (Gallons)	Date	Oil Field	Regulatory Category	Cause	Leak Detection	Investigation	Mitigation Measures
28,350	6/18/04	Prudhoe Bay	Process Piping	This incident was caused by valve or seal failure. A check valve failed on a 6-inch line during the restart phase of plant operations.	There was no information provided that may have determined how the leak was detected.	There was no information on the investigation of the spill.	No mitigation measures were identified in the report. However, the extensive third party analysis will be performed on the failed valve.
12,600	11/7/95	Prudhoe Bay	Process Piping	The cause of this incident has been determined to be corrosion/internal corrosion.	There was no information provided that may have determined how the leak was detected.	There was no information on the investigation of the spill.	There were no mitigation measures that were mentioned in the report.
11,611	2/26/02	Prudhoe Bay	Well	This spill was determined to have been caused by material failure of the pipe or weld	There was no information provided that may have determined how the leak was detected.	There was no information on the investigation of the spill.	There were no mitigation measures that were mentioned in the report.
10,500	10/6/98	Kuparuk River	Flowline	The cause of this incident has been determined to have been corrosion/ internal corrosion.	There was no information provided that may have determined how the leak was detected.	There was no information on the investigation of the spill.	It was determined that the best course of action would be to increase the frequency of inspections in corrosion monitoring program. However, the spill may have been associated with another injection line.

D.2 North Slope Loss-of-Integrity Spill Data Set, July1, 1995 to December 31,2009

NSSA ID	Oil Field	Spill Date	Volume Spilled (gallons)	Regulatory Category	Sub-category	Leak Detection	Primary Cause(s) of Failure	Contributing Cause(s) of Failure	Impacted Tundra	Impacted Frozen Water	Impacted Liquid Water	Square Footage of Tundra Impact
1227	Prudhoe Bay	7/18/95	5.0	Facility Oil Piping	Well Pad		Operator Error,					
1226	Prudhoe Bay	7/27/95	50.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
1225	Prudhoe Bay	7/29/95	10.0	Facility Oil Piping	Well Pad		Operator Error,					
1223	Prudhoe Bay	8/2/95	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1222	Kuparuk River	8/6/95	1,260.0	Facility Oil Piping	Well Pad		Corrosion,					
1220	Prudhoe Bay	8/15/95	25.0	Flowline	Operational 3-phase		Corrosion, External Corrosion,	Lack of Planned Maintenance Program,	yes		yes	486.0
1219	Prudhoe Bay	8/17/95	84.0	Process Piping	Processing Center		Valve/Seal Failure,					
1218	Prudhoe Bay	8/19/95	1.0	Facility Oil Piping	Well Pad		Operator Error,					
1216	Prudhoe Bay	9/24/95	10.0	Flowline	Maintenance Activity		Valve/Seal Failure,	Inadequate Procedures/ Policy,				
1215	Prudhoe Bay	10/4/95	10.0	Facility Oil Piping	Well Pad							
1213	Prudhoe Bay	10/9/95	12.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1212	Kuparuk River	10/23/95	269.0	Process Piping	Processing Center		Valve/Seal Failure,					
1211	Prudhoe Bay	10/25/95	2.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
1210	Prudhoe Bay	10/27/95	1.0	Facility Oil Piping	Well Pad							
1209	Prudhoe Bay	11/7/95	12,600.0	Process Piping	Processing Center		Corrosion, Internal Corrosion,					
1206	Prudhoe Bay	11/27/95	2.0	Process Piping	Processing Center		Valve/Seal Failure,					
1205	Kuparuk River	11/29/95	35.0	Facility Oil Piping	Well Pad		Operator Error,					
1203	Kuparuk River	12/3/95	2.0	Storage Tank								
1204	Prudhoe Bay	12/3/95	20.0	Well			Valve/Seal Failure,					
1202	Prudhoe Bay	12/11/95	5.0	Well			Valve/Seal Failure,					
1200	Kuparuk River	12/22/95	539.0	Flowline	Maintenance Activity		Valve/Seal Failure,					
1198	Kuparuk River	1/7/96	8,820.0	Flowline	Maintenance Activity	Visually	Valve/Seal Failure,					
1197	Prudhoe Bay	1/14/96	42.0	Facility Oil Piping	Well Pad		Operator Error,					
1196	Milne Point	1/27/96	10.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
1193	Prudhoe Bay	2/6/96	450.0	Facility Oil Piping	Processing Center		Operator Error,	Lack of Planned Maintenance Program,				

NSSA ID	Oil Field	Spill Date	Volume Spilled (gallons)	Regulatory Category	Sub-category	Leak Detection	Primary Cause(s) of Failure	Contributing Cause(s) of Failure	Impacted Tundra	Impacted Frozen Water	Impacted Liquid Water	Square Footage of Tundra Impact
1191	Prudhoe Bay	2/17/96	10.0	Process Piping	Processing Center		Valve/Seal Failure,					
1188	Kuparuk River	3/5/96	3.0	Facility Oil Piping	Well Pad		Operator Error,					
406	Prudhoe Bay	3/6/96	400.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,	Lack of Planned Maintenance Program,				
1185	Prudhoe Bay	3/11/96	3.0	Facility Oil Piping	Well Pad							
1182	Prudhoe Bay	3/28/96	30.0	Flowline	Operational 3-phase		Corrosion, Internal Corrosion,	Lack of Planned Maintenance Program,	yes	yes		400.0
800	Prudhoe Bay	4/11/96	168.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
1181	Prudhoe Bay	4/15/96	5.0	Flowline	Operational 3-phase	Visually	Thermal Expansion, Overpressure,	Inadequate Procedures/ Policy,	yes	yes		2,500.0
799	Prudhoe Bay	4/16/96	2.0	Well			Material Failure of Pipe or Weld,					
404	Prudhoe Bay	4/17/96	2,150.0	Process Piping	Processing Center		Thermal Expansion,					
1180	Kuparuk River	4/19/96	1.0	Flowline	Operational 3-phase		Valve/Seal Failure,					
402	Prudhoe Bay	4/21/96	168.0	Facility Oil Piping	Well Pad		Corrosion,					
1179	Kuparuk River	4/21/96	8.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
798	Prudhoe Bay	4/24/96	140.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
1176	Prudhoe Bay	5/10/96	5.0	Well			Valve/Seal Failure,					
1175	Milne Point	5/20/96	5.0	Process Piping	Processing Center		Operator Error,					
1174	Prudhoe Bay	5/24/96	84.0	Process Piping	Processing Center		Valve/Seal Failure,					
1171	Prudhoe Bay	6/1/96	5.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1169	Prudhoe Bay	6/7/96	10.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
796	Endicott	6/8/96	3.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
1167	Prudhoe Bay	6/17/96	42.0	Well			Valve/Seal Failure,					
1164	Milne Point	6/29/96	22.0	Process Piping	Processing Center		Valve/Seal Failure,					
1163	Kuparuk River	7/1/96	4.0	Facility Oil Piping	Well Pad	Visually	Operator Error,	Inadequate Implementation of Procedure/ Policy,				
1162	Prudhoe Bay	7/4/96	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					

NSSA ID	Oil Field	Spill Date	Volume Spilled (gallons)	Regulatory Category	Sub-category	Leak Detection	Primary Cause(s) of Failure	Contributing Cause(s) of Failure	Impacted Tundra	Impacted Frozen Water	Impacted Liquid Water	Square Footage of Tundra Impact
1161	Kuparuk River	7/6/96	630.0	Process Piping	Processing Center		Erosion, Internal Erosion,					
1160	Prudhoe Bay	7/7/96	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1158	Prudhoe Bay	7/8/96	10.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
1157	Prudhoe Bay	7/25/96	15.0	Process Piping	Processing Center		Valve/Seal Failure,					
1155	Prudhoe Bay	7/30/96	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1152	Prudhoe Bay	8/13/96	672.0	Process Piping	Processing Center		Valve/Seal Failure,					
1151	Kuparuk River	8/15/96	126.0	Flowline	Maintenance Activity			Lack of Planned Maintenance Program,				
1150	Kuparuk River	8/16/96	84.0	Oil Transmission Pipeline	Maintenance Activity	Visually	Operator Error,	Inadequate Implementation of Procedure/ Policy, Lack of Training, Lack of Planned Maintenance Program,				
1149	Prudhoe Bay	8/19/96	5.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
1148	Kuparuk River	8/21/96	120.0	Process Piping	Processing Center		Operator Error,					
1141	Prudhoe Bay	9/13/96	70.0	Facility Oil Piping	Well Pad		Erosion, Internal Erosion,					
1140	Prudhoe Bay	9/20/96	5.0	Facility Oil Piping	Well Pad		Operator Error,					
1139	Kuparuk River	9/23/96	5.0	Well			Valve/Seal Failure,					
1137	Prudhoe Bay	9/30/96	5.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
794	Milne Point	10/17/96	2,268.0	Flowline	Operational Produced Water		Valve/Seal Failure,					
1135	Prudhoe Bay	10/29/96	1.0	Process Piping	Seawater Pipeline		Valve/Seal Failure,					
1133	Prudhoe Bay	11/1/96	9,695.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					
1131	Endicott	11/10/96	5.0	Process Piping	Processing Center		Thermal Expansion,					
1128	Prudhoe Bay	11/22/96	294.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
1127	Prudhoe Bay	11/22/96	21.0	Process Piping	Processing Center		Operator Error,					

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1126	Kuparuk River	12/2/96	3.0	Flowline	Operational Produced Water	Visually	Valve/Seal Failure,					
1125	Prudhoe Bay	12/16/96	42.0	Flowline	Operational 3-phase		Material Failure of Pipe or Weld, Vibration (wind-induced/slugging),		yes	yes		1,200.0
1124	Prudhoe Bay	12/20/96	70.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
1123	Prudhoe Bay	12/31/96	100.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
1120	Kuparuk River	1/14/97	55.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1119	Milne Point	1/15/97	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1117	Milne Point	1/16/97	20.0	Flowline	Maintenance Activity		Valve/Seal Failure,	Lack of Planned Maintenance Program,				
1116	Prudhoe Bay	1/21/97	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
793	Prudhoe Bay	1/23/97	84.0	Process Piping	Processing Center		Erosion, External Erosion,					
1115	Kuparuk River	1/24/97	27.0	Process Piping	Processing Center		Corrosion,					
401	Prudhoe Bay	2/3/97	50.0	Facility Oil Piping	Well Pad		Operator Error,					
1110	Prudhoe Bay	3/8/97	220.0	Process Piping	Manifold Building		Valve/Seal Failure,	Inadequate Implementation of Procedure/ Policy, Lack of Planned Maintenance Program,	yes			330,000.0
1109	Prudhoe Bay	3/11/97	84.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
1106	Kuparuk River	3/12/97	2.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
791	Endicott	3/12/97	420.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
1107	Prudhoe Bay	3/12/97	420.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
399	Prudhoe Bay	3/24/97	7.0	Flowline	Maintenance Activity		Overpressure,					
789	Prudhoe Bay	3/31/97	420.0	Process Piping	Manifold Building		Valve/Seal Failure,					
1102	Kuparuk River	4/4/97	30.0	Facility Oil Piping	Well Pad		Operator Error,					
1099	Prudhoe Bay	4/27/97	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					

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1098	Prudhoe Bay	4/30/97	1,732.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
1097	Prudhoe Bay	5/1/97	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1096	Kuparuk River	5/3/97	98.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
1095	Kuparuk River	5/16/97	1,974.0	Flowline	Maintenance Activity		Valve/Seal Failure,					
1094	Prudhoe Bay	5/20/97	70.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
1093	Prudhoe Bay	5/23/97	5.0	Process Piping	Processing Center		Valve/Seal Failure,					
1090	Kuparuk River	6/3/97	25.0	Process Piping	Processing Center		Valve/Seal Failure,					
787	Prudhoe Bay	6/5/97	300.0	Well			Valve/Seal Failure,					
786	Milne Point	6/22/97	462.0	Well			Material Failure of Pipe or Weld,					
1088	Kuparuk River	6/24/97	1,260.0	Process Piping	Processing Center		Operator Error,					
1087	Prudhoe Bay	6/24/97	3.0	Flowline	Operational 3-phase		Valve/Seal Failure,					
1086	Kuparuk River	6/24/97	3.0	Process Piping	Seawater Pipeline	Visually	Valve/Seal Failure,					
1083	Kuparuk River	7/15/97	2,000.0	Flowline	Operational 3-phase		Corrosion, External Corrosion at or near weld joints,		yes		yes	2,100.0
1084	Prudhoe Bay	7/15/97	3,360.0	Flowline	Maintenance Activity		Valve/Seal Failure,	Inadequate Implementation of Procedure/ Policy, Lack of Planned Maintenance Program,				
1082	Prudhoe Bay	7/16/97	5.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1081	Prudhoe Bay	7/21/97	1,008.0	Process Piping	Processing Center		Valve/Seal Failure,					
1078	Kuparuk River	8/7/97	5.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1075	Kuparuk River	9/8/97	30.0	Process Piping	Processing Center		Valve/Seal Failure,					
1074	Prudhoe Bay	9/12/97	150.0	Flowline	Maintenance Activity	Visually	Valve/Seal Failure,					
398	Kuparuk River	9/13/97	15.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					

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396	Kuparuk River	9/15/97	6.0	Flowline	Operational 3-phase		Corrosion, External Corrosion,		yes		yes	348.0
1068	Prudhoe Bay	10/12/97	20.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
1067	Prudhoe Bay	10/14/97	84.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1064	Prudhoe Bay	10/16/97	3.0	Well			Valve/Seal Failure,					
1063	Prudhoe Bay	10/25/97	420.0	Process Piping	Seawater Pipeline		Material Failure of Pipe or Weld,					
1062	Kuparuk River	11/2/97	50.0	Process Piping	Processing Center		Valve/Seal Failure,					
1061	Kuparuk River	11/3/97	1.0	Process Piping	Processing Center		Valve/Seal Failure,					
395	Kuparuk River	11/15/97	3,030.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
1056	Kuparuk River	12/4/97	4.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1052	Kuparuk River	12/21/97	125.0	Process Piping	Processing Center		Operator Error,					
1051	Kuparuk River	1/10/98	63,000.0	Flowline	Operational Produced Water		Material Failure of Pipe or Weld,					
1050	Prudhoe Bay	1/12/98	42.0	Process Piping	Processing Center		Valve/Seal Failure,					
1046	Kuparuk River	1/26/98	152.0	Facility Oil Piping	Processing Center		Operator Error,					
1045	Prudhoe Bay	1/27/98	1,200.0	Process Piping	Processing Center		Valve/Seal Failure,					
1042	Prudhoe Bay	1/31/98	20.0	Facility Oil Piping	Well Pad							
1040	Prudhoe Bay	1/31/98	10.0	Storage Tank			Corrosion,					
1041	Prudhoe Bay	1/31/98	60.0	Process Piping	Processing Center		Operator Error,					
1039	Prudhoe Bay	2/2/98	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1035	Kuparuk River	3/3/98	205.0	Process Piping	Manifold Building		Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,					
1034	Prudhoe Bay	3/8/98	2.0	Well			Valve/Seal Failure,					
1032	Prudhoe Bay	3/9/98	20.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,					
1030	Prudhoe Bay	3/14/98	40.0	Process Piping	Processing Center		Valve/Seal Failure,					

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1029	Prudhoe Bay	3/15/98	2.0	Facility Oil Piping	Well Pad							
1027	Prudhoe Bay	3/17/98	5.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
1028	Prudhoe Bay	3/17/98	2.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
1026	Kuparuk River	3/21/98	1,260.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
1024	Prudhoe Bay	3/23/98	500.0	Process Piping	Processing Center		Operator Error,					
1023	Prudhoe Bay	3/25/98	600.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion, Material Failure of Pipe or Weld, Vibration (wind-induced/ slugging),		yes			90,000.0
1022	Prudhoe Bay	4/2/98	15.0	Well			Valve/Seal Failure,					
1021	Prudhoe Bay	4/6/98	10.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
1020	Kuparuk River	4/6/98	2.0	Process Piping	Processing Center		Operator Error,					
1017	Prudhoe Bay	4/8/98	110.0	Facility Oil Piping	Well Pad		Operator Error,					
1016	Kuparuk River	4/13/98	2,100.0	Flowline	Maintenance Activity		Valve/Seal Failure,	Inadequate Procedures/ Policy, Lack of Planned Maintenance Program,				
1014	Prudhoe Bay	4/16/98	25.0	Well								
1010	Kuparuk River	5/2/98	20.0	Well			Material Failure of Pipe or Weld,					
486	Milne Point	5/3/98	3,360.0	Storage Tank			Operator Error,					
1008	Kuparuk River	5/18/98	5.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
1007	Prudhoe Bay	5/26/98	10.0	Well			Valve/Seal Failure,					
1003	Prudhoe Bay	6/7/98	30.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
1002	Prudhoe Bay	6/10/98	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
785	Kuparuk River	6/10/98	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
998	Prudhoe Bay	6/17/98	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
996	Kuparuk River	6/20/98	2.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					

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993	Kuparuk River	7/14/98	84.0	Flowline	Maintenance Activity		Operator Error,					
991	Milne Point	7/19/98	168.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion, Erosion, Internal Erosion,					
989	Prudhoe Bay	8/2/98	20.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
987	Prudhoe Bay	8/9/98	10.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					
986	Endicott	8/21/98	1,000.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,	Poor Engineering Design,				
985	Kuparuk River	8/24/98	420.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,	Lack of Planned Maintenance Program,				
984	Prudhoe Bay	9/3/98	5.0	Process Piping	Processing Center		Operator Error,					
983	Kuparuk River	9/9/98	10.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
981	Prudhoe Bay	9/14/98	84.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
979	Kuparuk River	9/25/98	2.0	Flowline	Maintenance Activity	Visually	Operator Error,					
784	Milne Point	9/25/98	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
63	Kuparuk River	10/3/98	300.0	Process Piping	Processing Center		Valve/Seal Failure,					
393	Kuparuk River	10/6/98	10,500.0	Flowline	Operational Produced Water		Corrosion, Internal Corrosion,					
783	Prudhoe Bay	10/30/98	250.0	Facility Oil Piping	Well Pad		Overpressure,					
392	Milne Point	11/13/98	1,260.0	Process Piping	Processing Center		Valve/Seal Failure,					
169	Kuparuk River	11/21/98	115.0	Process Piping	Seawater Pipeline		Material Failure of Pipe or Weld,					
973	Prudhoe Bay	11/23/98	20.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
972	Prudhoe Bay	12/9/98	420.0	Process Piping	Processing Center		Corrosion, Internal Corrosion,					
782	Prudhoe Bay	12/18/98	15.0	Process Piping	Processing Center		Thermal Expansion, Valve/Seal Failure,					
391	Prudhoe Bay	1/28/99	300.0	Process Piping	Processing Center		Valve/Seal Failure,					

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969	Kuparuk River	1/31/99	10.0	Process Piping	Seawater Pipeline		Material Failure of Pipe or Weld,					
968	Prudhoe Bay	2/3/99	60.0	Flowline	Maintenance Activity	Visually	Valve/Seal Failure,	Lack of Planned Maintenance Program,				
168	Prudhoe Bay	2/18/99	150.0	Flowline	Maintenance Activity	Visually	Corrosion, Internal Corrosion, Erosion, Internal Erosion, Valve/Seal Failure,	Lack of Planned Maintenance Program,				
967	Prudhoe Bay	3/3/99	15.0	Flowline	Maintenance Activity		Valve/Seal Failure, Operator Error,	Lack of Procedure/ Policy, Inadequate Procedures/ Policy,				
966	Kuparuk River	3/4/99	110.0	Process Piping	Seawater Pipeline		Material Failure of Pipe or Weld,					
390	Prudhoe Bay	3/9/99	44.0	Process Piping	Processing Center		Erosion, Internal Erosion,					
965	Prudhoe Bay	3/13/99	10.0	Facility Oil Piping	Well Pad		Operator Error,					
963	Prudhoe Bay	3/20/99	210.0	Process Piping	Processing Center		Valve/Seal Failure,					
523	Milne Point	4/4/99	217.0	Process Piping	Processing Center		Valve/Seal Failure,					
960	Prudhoe Bay	4/18/99	300.0	Flowline	Maintenance Activity		Corrosion, Internal Corrosion, Overpressure,	Inadequate Implementation of Procedure/ Policy, Poor Engineering Design,				
957	Kuparuk River	5/28/99	210.0	Flowline	Maintenance Activity		Valve/Seal Failure,					
956	Prudhoe Bay	5/30/99	10.0	Process Piping	Processing Center		Valve/Seal Failure,					
386	Prudhoe Bay	6/10/99	6,384.0	Facility Oil Piping	Well Pad		Corrosion, External Corrosion,		yes			
954	Kuparuk River	6/11/99	98.0	Flowline	Maintenance Activity		Valve/Seal Failure,					
953	Prudhoe Bay	6/16/99	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
949	Prudhoe Bay	7/17/99	62.0	Facility Oil Piping	Well Pad		Erosion, Internal Erosion,					

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385	Kuparuk River	7/23/99	6,300.0	Flowline	Operational Produced Water		Corrosion, External Corrosion at or near weld joints,		yes		yes	6,500.0
946	Prudhoe Bay	7/29/99	2.0	Well			Valve/Seal Failure,					
945	Prudhoe Bay	7/30/99	200.0	Process Piping	Processing Center		Operator Error,					
944	Prudhoe Bay	8/2/99	2.0	Well			Valve/Seal Failure,					
942	Prudhoe Bay	8/7/99	60.0	Process Piping	Processing Center		Valve/Seal Failure,					
940	Kuparuk River	8/15/99	1,350.0	Flowline	Maintenance Activity		Valve/Seal Failure,					
939	Milne Point	8/24/99	2.0	Facility Oil Piping	Well Pad		Operator Error,					
937	Prudhoe Bay	9/9/99	2.0	Facility Oil Piping	Well Pad		Overpressure,					
781	Prudhoe Bay	9/18/99	10.0	Well								
936	Kuparuk River	9/20/99	1.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
935	Milne Point	9/21/99	9.0	Facility Oil Piping	Well Pad		Erosion, Internal Erosion,					
931	Kuparuk River	10/8/99	30.0	Process Piping	Processing Center		Valve/Seal Failure,					
930	Prudhoe Bay	10/10/99	420.0	Flowline	Maintenance Activity		Valve/Seal Failure,					
928	Prudhoe Bay	10/19/99	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
927	Prudhoe Bay	10/23/99	10.0	Process Piping	Processing Center		Corrosion, Internal Corrosion,					
925	Kuparuk River	10/30/99	5.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
924	Prudhoe Bay	11/5/99	42.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
920	Prudhoe Bay	11/24/99	2.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
914	Prudhoe Bay	1/4/00	2.0	Facility Oil Piping	Well Pad		Operator Error,					
910	Prudhoe Bay	2/4/00	50.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					
909	Prudhoe Bay	2/6/00	60.0	Well			Valve/Seal Failure,					
906	Badami	2/14/00	200.0	Process Piping	Manifold Building		Corrosion,					
907	Kuparuk River	2/14/00	225.0	Flowline	Maintenance Activity		Valve/Seal Failure,					
904	Prudhoe Bay	3/13/00	1,000.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
902	Prudhoe Bay	3/20/00	1,000.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					

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900	Prudhoe Bay	3/20/00	25.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
901	Prudhoe Bay	3/20/00	3.0	Well			Valve/Seal Failure,					
780	Kuparuk River	3/24/00	10.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
897	Prudhoe Bay	4/6/00	3.0	Well			Valve/Seal Failure,					
890	Prudhoe Bay	4/29/00	25.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
889	Prudhoe Bay	4/29/00	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
384	Kuparuk River	5/6/00	200.0	Well			Valve/Seal Failure,					
887	Prudhoe Bay	5/6/00	10.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
383	Prudhoe Bay	5/10/00	10.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
382	Prudhoe Bay	6/8/00	100.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
883	Prudhoe Bay	6/19/00	50.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
881	Kuparuk River	6/20/00	3.0	Facility Oil Piping			Corrosion,					
878	Prudhoe Bay	6/23/00	2.0	Well			Material Failure of Pipe or Weld,					
381	Prudhoe Bay	6/24/00	5.0	Flowline	Operational 3-phase	Visually	Thermal Expansion,	Inadequate Implementation of Procedure/ Policy,				
877	Prudhoe Bay	6/25/00	12.0	Process Piping	Processing Center		Overpressure,					
379	Milne Point	6/27/00	200.0	Process Piping	Processing Center		Erosion, Internal Erosion,					
377	Prudhoe Bay	7/10/00	1.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
874	Kuparuk River	7/12/00	425.0	Flowline	Maintenance Activity		Valve/Seal Failure,		yes		yes	10.0
779	Prudhoe Bay	7/16/00	10.0	Well			Material Failure of Pipe or Weld,					
873	Milne Point	7/20/00	84.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
871	Prudhoe Bay	7/30/00	20.0	Well			Valve/Seal Failure,					
870	Prudhoe Bay	8/8/00	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
869	Kuparuk River	8/13/00	3.0	Facility Oil Piping	Well Pad		Operator Error,					

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521	Prudhoe Bay	8/15/00	15.0	Process Piping	Processing Center		Valve/Seal Failure,					
867	Prudhoe Bay	8/20/00	110.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
864	Badami	9/17/00	5.0	Process Piping	Processing Center		Corrosion,					
863	Prudhoe Bay	9/17/00	3.0	Well			Valve/Seal Failure,					
862	Prudhoe Bay	9/23/00	10.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
376	Kuparuk River	11/15/00	2.0	Oil Transmission Pipeline	Operational		Valve/Seal Failure, Operator Error,	Inadequate Implementation of Procedure/ Policy, Lack of Training, Poor Oversight of Personnel,	yes	yes		400.0
857	Prudhoe Bay	12/1/00	630.0	Flowline	Operational 3-phase	Visually	Thermal Expansion, Valve/Seal Failure,	Inadequate Procedures/ Policy, Inadequate Implementation of Procedure/ Policy, Poor Oversight of Personnel,	yes	yes		
856	Prudhoe Bay	12/1/00	85.0	Facility Oil Piping	Processing Center		Valve/Seal Failure,					
61	Kuparuk River	12/2/00	150.0	Process Piping	Processing Center		Valve/Seal Failure,					
375	Milne Point	12/10/00	7,754.0	Process Piping	Processing Center		Valve/Seal Failure,					
855	Kuparuk River	12/27/00	70.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
778	Prudhoe Bay	2/3/01	100.0	Process Piping	Processing Center		Operator Error,					
848	Prudhoe Bay	2/4/01	100.0	Process Piping	Processing Center		Operator Error,					
844	Prudhoe Bay	2/19/01	5,345.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion, Erosion, Internal Erosion,					
836	Prudhoe Bay	3/23/01	2.0	Facility Oil Piping	Well Pad		Operator Error,	Inadequate Implementation of Procedure/ Policy, Lack of Training, Poor Oversight of Personnel,				
373	Kuparuk River	3/25/01	40.0	Process Piping	Seawater Pipeline		Thermal Expansion,		yes			60.0

NSSA ID	Oil Field	Spill Date	Volume Spilled (gallons)	Regulatory Category	Sub-category	Leak Detection	Primary Cause(s) of Failure	Contributing Cause(s) of Failure	Impacted Tundra	Impacted Frozen Water	Impacted Liquid Water	Square Footage of Tundra Impact
372	Kuparuk River	4/15/01	92,400.0	Flowline	Operational Produced Water	Visually	Corrosion, External Corrosion at or near weld joints,	Inadequate Implementation of Procedure/ Policy, Poor Engineering Design,	yes	yes		34,940.0
834	Prudhoe Bay	4/15/01	146.0	Process Piping	Processing Center		Corrosion, Internal Corrosion,					
832	Prudhoe Bay	4/20/01	500.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					
775	Endicott	4/23/01	630.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
831	Prudhoe Bay	4/23/01	630.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
828	Prudhoe Bay	5/18/01	2.0	Well			Material Failure of Pipe or Weld,					
827	Prudhoe Bay	5/26/01	125.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
824	Prudhoe Bay	6/14/01	210.0	Process Piping	Seawater Pipeline		Valve/Seal Failure,					
823	Prudhoe Bay	6/14/01	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
822	Prudhoe Bay	6/20/01	3.0	Well			Valve/Seal Failure,					
821	Prudhoe Bay	6/22/01	3.0	Well			Valve/Seal Failure,					
820	Prudhoe Bay	6/23/01	2.0	Flowline	Maintenance Activity	Visually	Operator Error,	Inadequate Procedures/ Policy, Lack of Planned Maintenance Program,				
817	Prudhoe Bay	7/2/01	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
370	Prudhoe Bay	7/7/01	200.0	Facility Oil Piping	Well Pad	Visually	Corrosion, External Corrosion,		yes			
369	Prudhoe Bay	7/21/01	420.0	Flowline	Operational 3-phase	Visually	Corrosion, External Corrosion at or near weld joints,		yes		yes	20,473.0
814	Prudhoe Bay	8/3/01	3.0	Facility Oil Piping	Well Pad							
368	Prudhoe Bay	8/16/01	1.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
478	Prudhoe Bay	8/29/01	5.0	Process Piping	Processing Center		Operator Error,					
367	Kuparuk River	8/30/01	1.0	Oil Transmission Pipeline	Operational		Valve/Seal Failure,					
771	Prudhoe Bay	9/5/01	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					

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811	Kuparuk River	9/10/01	25.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
366	Prudhoe Bay	9/18/01	3.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
165	Prudhoe Bay	9/29/01	1.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
810	Prudhoe Bay	10/5/01	2.0	Process Piping	Processing Center		Operator Error,					
769	Prudhoe Bay	10/27/01	1.0	Process Piping			Valve/Seal Failure,					
164	North Star	11/15/01	84.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
163	Prudhoe Bay	11/16/01	3.0	Well			Valve/Seal Failure,					
365	Prudhoe Bay	11/24/01	80.0	Process Piping	Processing Center		Operator Error,					
766	Kuparuk River	11/30/01	1,259.0	Facility Oil Piping	Well Pad		Erosion, External Erosion,					
475	North Star	12/5/01	2.0	Facility Oil Piping	Processing Center		Operator Error,					
474	Prudhoe Bay	12/15/01	2,600.0	Storage Tank			Material Failure of Pipe or Weld,					
364	Prudhoe Bay	12/20/01	100.0	Process Piping	Processing Center		Operator Error,					
765	Prudhoe Bay	12/23/01	5.0	Well			Material Failure of Pipe or Weld,					
161	North Star	12/26/01	10.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
764	Prudhoe Bay	12/28/01	20.0	Well			Material Failure of Pipe or Weld,					
361	Prudhoe Bay	1/14/02	115.0	Well			Erosion, Internal Erosion,					
360	Prudhoe Bay	1/23/02	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
359	Milne Point	2/3/02	75.0	Flowline	Maintenance Activity	Visually	Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related, Valve/Seal Failure,	Inadequate Implementation of Procedure/ Policy,				
358	Prudhoe Bay	2/9/02	2.0	Process Piping	Manifold Building		Overpressure,					
357	Prudhoe Bay	2/16/02	1.0	Process Piping	Seawater Pipeline		Valve/Seal Failure,					
355	Kuparuk River	2/17/02	22.0	Flowline	Maintenance Activity		Operator Error,	Inadequate Implementation of Procedure/ Policy,				

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759	Prudhoe Bay	2/26/02	11,611.0	Well			Material Failure of Pipe or Weld,					
757	Colville River, Alpine	3/10/02	4,998.0	Process Piping	Seawater Pipeline		Erosion,					
160	Prudhoe Bay	3/20/02	10.0	Process Piping	Processing Center		Valve/Seal Failure,					
753	Kuparuk River	4/7/02	1,200.0	Facility Oil Piping	Well Pad		Erosion, Internal Erosion,					
751	Prudhoe Bay	4/17/02	84.0	Well			Corrosion, Internal Corrosion,					
750	Prudhoe Bay	4/19/02	1.0	Facility Oil Piping								
749	Prudhoe Bay	4/24/02	40.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
747	Kuparuk River	4/27/02	35.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
472	Prudhoe Bay	5/6/02	100.0	Storage Tank			Material Failure of Pipe or Weld,					
353	Milne Point	5/6/02	15.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
746	Prudhoe Bay	5/21/02	84.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
351	Prudhoe Bay	5/27/02	420.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
350	Prudhoe Bay	5/29/02	4,469.0	Process Piping	Processing Center		Valve/Seal Failure,					
349	Prudhoe Bay	6/1/02	1.0	Facility Oil Piping	Well Pad	Visually	Corrosion,		yes		yes	25.0
347	Prudhoe Bay	6/2/02	5.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
101	Prudhoe Bay	6/21/02	12.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
102	Milne Point	6/21/02	12.0	Facility Oil Piping			Valve/Seal Failure,					
345	Prudhoe Bay	7/14/02	622.0	Process Piping	Processing Center	Visually	Erosion, Internal Erosion, Valve/Seal Failure,	Lack of Planned Maintenance Program,				
808	Prudhoe Bay	7/14/02	1.0	Process Piping	Seawater Pipeline		Valve/Seal Failure,					
744	Prudhoe Bay	7/23/02	4.0	Well			Material Failure of Pipe or Weld,					
343	Kuparuk River	7/25/02	6.0	Facility Oil Piping	Processing Center		Material Failure of Pipe or Weld,					
743	Prudhoe Bay	8/1/02	6,301.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,		yes			

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471	Milne Point	8/6/02	750.0	Process Piping	Processing Center		Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,					
742	Prudhoe Bay	8/16/02	1,050.0	Process Piping	Seawater Pipeline							
35	Prudhoe Bay	8/22/02	15.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
469	Prudhoe Bay	8/26/02	2.0	Storage Tank			Valve/Seal Failure,					
340	Prudhoe Bay	9/26/02	4.0	Flowline	Operational 3-phase		Corrosion, External Corrosion,	Poor Engineering Design,				
740	Prudhoe Bay	10/5/02	2.0	Well			Valve/Seal Failure,					
339	Prudhoe Bay	10/10/02	20.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
338	Prudhoe Bay	10/16/02	966.0	Flowline	Operational 3-phase	Visually	Operator Error,	Lack of Procedure/ Policy, Inadequate Implementation of Procedure/ Policy, Lack of Training,				
467	Prudhoe Bay	12/6/02	2.0	Storage Tank			Operator Error,					
337	Prudhoe Bay	12/6/02	6.0	Facility Oil Piping	Well Pad		Overpressure,		yes			
336	Prudhoe Bay	12/8/02	12.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
59	Badami	12/24/02	80.0	Process Piping	Processing Center		Valve/Seal Failure,					
335	Prudhoe Bay	1/10/03	9.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
334	Prudhoe Bay	1/19/03	5.0	Flowline	Operational Produced Water	Visually	Valve/Seal Failure,					
332	Prudhoe Bay	1/20/03	38.0	Flowline	Operational 3-phase	Visually	Material Failure of Pipe or Weld,					
331	Prudhoe Bay	1/24/03	15.0	Flowline	Operational 3-phase	Visually	Corrosion, External Corrosion,	Poor Engineering Design,	yes	yes		1,124.0
731	Prudhoe Bay	3/17/03	15.0	Well			Valve/Seal Failure,					
730	Kuparuk River	3/20/03	1.0	Process Piping	Seawater Pipeline		Material Failure of Pipe or Weld,					

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152	Endicott	3/21/03	4,410.0	Process Piping	Seawater Pipeline							
329	Kuparuk River	3/30/03	500.0	Facility Oil Piping	Well Pad		Operator Error,					
328	Prudhoe Bay	4/3/03	100.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
728	Prudhoe Bay	4/6/03	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
150	Kuparuk River	4/13/03	110.0	Flowline	Maintenance Activity	Visually	Valve/Seal Failure,					
327	Kuparuk River	4/14/03	5,670.0	Process Piping	Processing Center		Corrosion, External Corrosion,					
324	Kuparuk River	4/26/03	40.0	Flowline	Operational 3-phase		Thermal Expansion,	Inadequate Implementation of Procedure/ Policy,	yes	yes		200.0
323	Prudhoe Bay	5/5/03	15.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
322	Prudhoe Bay	5/11/03	310.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
726	Prudhoe Bay	5/12/03	30.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
321	Prudhoe Bay	5/25/03	1,681.0	Process Piping	Processing Center		Corrosion, External Corrosion,					
723	Kuparuk River	5/25/03	30.0	Well			Material Failure of Pipe or Weld,					
320	Prudhoe Bay	5/27/03	6,000.0	Flowline	Operational 3-phase	Visually	Corrosion, External Corrosion at or near weld joints,	Inadequate Implementation of Procedure/ Policy, Poor Engineering Design,	yes	yes		14,810.0
460	Prudhoe Bay	5/29/03	20.0	Storage Tank			Operator Error,					
319	Prudhoe Bay	6/2/03	5.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
721	Prudhoe Bay	6/3/03	6.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
722	Prudhoe Bay	6/3/03	5.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
719	Prudhoe Bay	6/7/03	20.0	Well			Material Failure of Pipe or Weld,					
149	Prudhoe Bay	6/10/03	2.0	Well			Valve/Seal Failure,					
718	Prudhoe Bay	6/13/03	126.0	Well			Valve/Seal Failure,					

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717	Prudhoe Bay	6/25/03	10.0	Well			Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,					
714	Prudhoe Bay	7/2/03	5.0	Well			Material Failure of Pipe or Weld,					
715	Prudhoe Bay	7/2/03	2.0	Facility Oil Piping	Well Pad		Operator Error,					
713	Prudhoe Bay	7/4/03	10.0	Well			Material Failure of Pipe or Weld,					
712	Prudhoe Bay	7/4/03	2.0	Well			Material Failure of Pipe or Weld,					
711	Prudhoe Bay	7/12/03	10.0	Process Piping	Processing Center		Valve/Seal Failure,					
148	North Star	7/18/03	2.0	Facility Oil Piping	Well Pad							
316	Prudhoe Bay	7/25/03	84.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
709	Prudhoe Bay	8/1/03	2.0	Well			Material Failure of Pipe or Weld,					
315	Prudhoe Bay	8/7/03	1.0	Process Piping	Processing Center		Corrosion,					
147	Prudhoe Bay	8/10/03	2.0	Facility Oil Piping	Well Pad		Operator Error,					
708	Prudhoe Bay	8/20/03	1.0	Facility Oil Piping	Well Pad							
707	Prudhoe Bay	9/11/03	10.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
146	Prudhoe Bay	9/12/03	50.0	Facility Oil Piping	Well Pad							
706	Prudhoe Bay	9/13/03	84.0	Flowline	Maintenance Activity	Visually	Overpressure,	Inadequate Implementation of Procedure/ Policy, Lack of Planned Maintenance Program,				
314	Prudhoe Bay	9/27/03	5.0	Facility Oil Piping	Well Pad		Overpressure,		yes			
705	Prudhoe Bay	10/12/03	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
702	Kuparuk River	11/17/03	2.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
409	Prudhoe Bay	11/17/03	15.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
701	Prudhoe Bay	11/21/03	10.0	Well			Valve/Seal Failure,					

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700	Milne Point	11/26/03	120.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
145	Milne Point	12/6/03	4,831.0	Facility Oil Piping	Well Pad							
144	Prudhoe Bay	12/11/03	25.0	Process Piping	Seawater Pipeline		Operator Error,					
697	Prudhoe Bay	12/23/03	2.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
696	Prudhoe Bay	1/2/04	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
695	Prudhoe Bay	1/14/04	2.0	Well			Operator Error,					
693	Prudhoe Bay	2/28/04	2.0	Well								
312	Prudhoe Bay	2/29/04	2.0	Facility Oil Piping	Well Pad		Operator Error,					
311	Kuparuk River	3/17/04	1,000.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,	Inadequate Procedures/ Policy, Poor Engineering Design,		yes		
455	Kuparuk River	3/18/04	2,520.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
310	Kuparuk River	3/27/04	60.0	Process Piping	Processing Center		Corrosion, Internal Corrosion,					
689	Prudhoe Bay	4/26/04	5.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
309	Kuparuk River	4/26/04	136.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
688	Prudhoe Bay	4/27/04	2.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
687	Milne Point	4/27/04	2.0	Process Piping	Manifold Building		Operator Error,					
686	Prudhoe Bay	5/9/04	210.0	Facility Oil Piping	Well Pad							
307	Kuparuk River	5/12/04	763.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
57	Kuparuk River	5/14/04	678.0	Process Piping	Processing Center		Valve/Seal Failure,					
685	Prudhoe Bay	5/15/04	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
684	Prudhoe Bay	5/20/04	15.0	Well			Material Failure of Pipe or Weld,					
683	Milne Point	5/23/04	18.0	Well			Valve/Seal Failure,					
682	Prudhoe Bay	5/24/04	15.0	Well								
681	Prudhoe Bay	5/29/04	3.0	Well			Material Failure of Pipe or Weld,					
305	Kuparuk River	6/5/04	98.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					

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680	Prudhoe Bay	6/7/04	20.0	Well			Material Failure of Pipe or Weld,					
453	Prudhoe Bay	6/8/04	250.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
303	Prudhoe Bay	6/14/04	30.0	Flowline	Maintenance Activity		Corrosion, Internal Corrosion,					
302	Prudhoe Bay	6/18/04	28,350.0	Process Piping	Processing Center		Valve/Seal Failure,					
301	Prudhoe Bay	6/23/04	8.0	Process Piping	Processing Center		Valve/Seal Failure,					
676	Prudhoe Bay	6/24/04	80.0	Well			Material Failure of Pipe or Weld,					
675	Prudhoe Bay	6/25/04	3.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
674	Prudhoe Bay	6/29/04	2.0	Flowline	Operational 3-phase	Visually	Valve/Seal Failure,	Inadequate Implementation of Procedure/ Policy,				
673	Prudhoe Bay	7/3/04	20.0	Facility Oil Piping	Well Pad		Thermal Expansion,	Inadequate Implementation of Procedure/ Policy,				
672	Prudhoe Bay	7/7/04	2.0	Facility Oil Piping	Well Pad							
142	Kuparuk River	7/15/04	252.0	Flowline	Maintenance Activity	Visually	Valve/Seal Failure,		yes		yes	220.0
141	Prudhoe Bay	7/18/04	130.0	Facility Oil Piping	Well Pad		Erosion, Internal Erosion,					
671	Prudhoe Bay	7/19/04	120.0	Well			Valve/Seal Failure,					
300	Prudhoe Bay	7/21/04	1.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
670	Prudhoe Bay	7/23/04	5.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
669	Prudhoe Bay	7/26/04	1.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
298	Prudhoe Bay	8/31/04	153.0	Flowline	Operational 3-phase	Visually	Corrosion, External Corrosion, Material Failure of Pipe or Weld, Vibration (wind-induced/ slugging),		yes		yes	30.0
667	Prudhoe Bay	9/3/04	4.0	Well			Material Failure of Pipe or Weld,					

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665	Prudhoe Bay	9/11/04	1,260.0	Process Piping	Seawater Pipeline		Operator Error,					
297	Prudhoe Bay	11/7/04	275.0	Process Piping	Seawater Pipeline		Corrosion, External Corrosion,					
294	Milne Point	12/4/04	595.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
296	Prudhoe Bay	12/4/04	5,250.0	Flowline	Operational Produced Water	Visually and Leak Detection System	Valve/Seal Failure,		yes	yes		4,000.0
660	Prudhoe Bay	12/7/04	65.0	Process Piping	Seawater Pipeline							
658	Prudhoe Bay	12/12/04	80.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					
56	Milne Point	12/29/04	2.0	Process Piping	Processing Center		Valve/Seal Failure,					
657	Prudhoe Bay	1/3/05	126.0	Process Piping	Processing Center		Operator Error,					
293	Prudhoe Bay	1/9/05	275.0	Process Piping	Processing Center		Corrosion, External Corrosion,					
140	Kuparuk River	1/16/05	644.0	Flowline	Maintenance Activity	Visually	Valve/Seal Failure,	Inadequate Procedures/ Policy, Lack of Training,				
139	Prudhoe Bay	1/28/05	80.0	Process Piping	Processing Center		Valve/Seal Failure,					
292	Prudhoe Bay	2/4/05	70.0	Process Piping	Seawater Pipeline		Corrosion, External Corrosion,					
449	Prudhoe Bay	2/5/05	1.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
656	Prudhoe Bay	2/13/05	275.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					
290	Prudhoe Bay	2/23/05	150.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
138	Kuparuk River	3/13/05	4.0	Oil Transmission Pipeline	Maintenance Activity		Valve/Seal Failure,					
652	Milne Point	3/14/05	126.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
289	Kuparuk River	3/26/05	51,198.0	Well			Corrosion, Internal Corrosion,					
137	Prudhoe Bay	4/4/05	200.0	Flowline	Maintenance Activity		Valve/Seal Failure,					
650	Prudhoe Bay	4/5/05	126.0	Process Piping								
288	Prudhoe Bay	4/5/05	126.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					

NSSA ID	Oil Field	Spill Date	Volume Spilled (gallons)	Regulatory Category	Sub-category	Leak Detection	Primary Cause(s) of Failure	Contributing Cause(s) of Failure	Impacted Tundra	Impacted Frozen Water	Impacted Liquid Water	Square Footage of Tundra Impact
649	Prudhoe Bay	4/10/05	2.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
648	Endicott	4/11/05	7.0	Well			Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,					
287	Prudhoe Bay	4/12/05	1,260.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
647	Milne Point	5/16/05	15.0	Well			Valve/Seal Failure,					
285	Prudhoe Bay	5/20/05	5.0	Process Piping	Processing Center		Overpressure,					
645	Prudhoe Bay	6/3/05	100.0	Well			Material Failure of Pipe or Weld,					
284	Prudhoe Bay	6/3/05	4,600.0	Process Piping	Processing Center		Operator Error,					
644	Milne Point	6/7/05	6.0	Well			Valve/Seal Failure,					
643	Kuparuk River	6/8/05	200.0	Well			Corrosion, Internal Corrosion,					
642	Prudhoe Bay	6/17/05	10.0	Process Piping	Seawater Pipeline		Thermal Expansion,					
641	Prudhoe Bay	6/22/05	5.0	Well			Material Failure of Pipe or Weld,					
283	Prudhoe Bay	7/8/05	15.0	Process Piping	Processing Center		Operator Error,					
281	Kuparuk River	7/19/05	13.0	Facility Oil Piping	Well Pad		Corrosion, External Corrosion at or near weld joints, Internal Corrosion,					
280	Kuparuk River	8/9/05	483.0	Flowline	Maintenance Activity		Corrosion, Internal Corrosion,	Lack of Planned Maintenance Program,				
639	Prudhoe Bay	8/19/05	3.0	Well			Thermal Expansion,					
637	Prudhoe Bay	9/4/05	35.0	Well			Overpressure,					
636	Prudhoe Bay	9/20/05	5.0	Well			Valve/Seal Failure,					
513	Prudhoe Bay	9/26/05	150.0	Process Piping	Processing Center		Operator Error,					
26	Kuparuk River	10/2/05	500.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
135	Prudhoe Bay	10/14/05	200.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
633	Milne Point	10/15/05	80.0	Facility Oil Piping	Well Pad		Operator Error,					

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279	Milne Point	10/18/05	55.0	Process Piping	Processing Center		Thermal Expansion,					
277	Kuparuk River	10/26/05	16.0	Flowline	Operational 3-phase	Visually	Corrosion, External Corrosion at or near weld joints,		yes	yes		200.0
276	Prudhoe Bay	10/28/05	10.0	Process Piping	Seawater Pipeline		Corrosion,					
275	Prudhoe Bay	11/4/05	80.0	Process Piping	Seawater Pipeline		Valve/Seal Failure,	Inadequate Procedures/ Policy, Inadequate Implementation of Procedure/ Policy, Lack of Training, Poor Oversight of Personnel,				
444	Prudhoe Bay	11/14/05	250.0	Process Piping	Processing Center		Thermal Expansion,					
631	Prudhoe Bay	12/8/05	2.0	Well			Valve/Seal Failure,					
274	Kuparuk River	12/15/05	40.0	Facility Oil Piping	Well Pad	Visually	Thermal Expansion,	Lack of Procedure/ Policy, Inadequate Procedures/ Policy, Lack of Training, Poor Oversight of Personnel,				
273	Colville River, Alpine	12/18/05	1.0	Oil Transmission Pipeline	Operational	Visually	Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,	Poor Engineering Design,	yes	yes		
629	Kuparuk River	12/25/05	630.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
627	Prudhoe Bay	1/11/06	400.0	Process Piping	Processing Center		Valve/Seal Failure,					
626	Prudhoe Bay	1/20/06	25.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					

NSSA ID	Oil Field	Spill Date	Volume Spilled (gallons)	Regulatory Category	Sub-category	Leak Detection	Primary Cause(s) of Failure	Contributing Cause(s) of Failure	Impacted Tundra	Impacted Frozen Water	Impacted Liquid Water	Square Footage of Tundra Impact
272	Kuparuk River	1/29/06	42.0	Facility Oil Piping	Well Pad	Visually	Thermal Expansion,	Lack of Procedure/ Policy, Inadequate Implementation of Procedure/ Policy, Poor Engineering Design,	yes	yes		1,600.0
440	Kuparuk River	2/23/06	3.0	Facility Oil Piping	Well Pad		Thermal Expansion,					
270	Kuparuk River	2/24/06	22.0	Process Piping	Seawater Pipeline		Material Failure of Pipe or Weld,					
269	Prudhoe Bay	3/2/06	1.0	Process Piping	Seawater Pipeline		Corrosion,					
268	Prudhoe Bay	3/2/06	212,252.0	Oil Transmission Pipeline	Operational	Odor	Corrosion, Internal Corrosion,	Inadequate Procedures/ Policy, Lack of Planned Maintenance Program,	yes	yes		84,071.0
266	Kuparuk River	3/9/06	700.0	Flowline	Operational 3-phase		Corrosion, Internal Corrosion,		yes	yes		2,003.0
624	Kuparuk River	3/13/06	8.0	Well			Material Failure of Pipe or Weld,					
265	Prudhoe Bay	3/25/06	840.0	Process Piping	Seawater Pipeline		Material Failure of Pipe or Weld,					
264	Prudhoe Bay	3/30/06	420.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
55	Prudhoe Bay	4/4/06	200.0	Process Piping	Processing Center		Valve/Seal Failure,					
262	Prudhoe Bay	4/5/06	70.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
621	Kuparuk River	4/6/06	220.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
261	Prudhoe Bay	4/8/06	400.0	Process Piping	Processing Center		Valve/Seal Failure,					
619	Badami	4/9/06	10.0	Facility Oil Piping	Well Pad		Overpressure, Operator Error,					
618	Prudhoe Bay	4/21/06	10.0	Process Piping	Processing Center		Corrosion, Internal Corrosion,					
260	Prudhoe Bay	4/21/06	3.0	Process Piping	Seawater Pipeline		Valve/Seal Failure,					
54	Prudhoe Bay	5/2/06	1,122.0	Process Piping	Processing Center		Valve/Seal Failure,					

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53	Prudhoe Bay	5/10/06	100.0	Process Piping	Processing Center		Valve/Seal Failure,					
617	Prudhoe Bay	5/13/06	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
616	Prudhoe Bay	5/22/06	10.0	Well								
615	Prudhoe Bay	5/24/06	1,050.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					
614	Milne Point	5/25/06	4.0	Well			Valve/Seal Failure,					
613	Prudhoe Bay	6/3/06	8.0	Well			Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,					
256	Kuparuk River	6/15/06	5.0	Flowline	Operational Produced Water	Visually	Corrosion, External Corrosion at or near weld joints,	Inadequate Implementation of Procedure/ Policy, Lack of Planned Maintenance Program,				
611	Kuparuk River	6/21/06	253.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					
609	Prudhoe Bay	6/23/06	84.0	Facility Oil Piping	Well Pad		Overpressure,					
608	Prudhoe Bay	6/25/06	10.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
255	Prudhoe Bay	7/15/06	420.0	Facility Oil Piping	Well Pad		Overpressure,					
607	Prudhoe Bay	7/19/06	20.0	Well			Valve/Seal Failure,					
606	Prudhoe Bay	7/21/06	5.0	Well			Material Failure of Pipe or Weld,					
604	Prudhoe Bay	7/25/06	10.0	Well			Operator Error,					
603	Prudhoe Bay	7/30/06	10.0	Well			Material Failure of Pipe or Weld,					
254	Prudhoe Bay	8/6/06	5,040.0	Oil Transmission Pipeline	Operational	Visually	Corrosion, Internal Corrosion,	Inadequate Procedures/ Policy, Lack of Planned Maintenance Program,	yes		yes	6,149.0

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253	Prudhoe Bay	8/7/06	1,000.0	Process Piping	Processing Center		Material Failure of Pipe or Weld, Vibration (wind-induced/slugging),					
252	Prudhoe Bay	8/11/06	630.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion,					
600	Endicott	8/15/06	66.0	Well			Overpressure,					
251	Prudhoe Bay	8/23/06	130.0	Process Piping	Processing Center		Corrosion, Internal Corrosion,					
250	Prudhoe Bay	8/26/06	3.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
131	Kuparuk River	8/30/06	190.0	Flowline	Maintenance Activity	Visually	Valve/Seal Failure,					
598	Prudhoe Bay	9/18/06	630.0	Well			Material Failure of Pipe or Weld,					
597	Prudhoe Bay	9/22/06	84.0	Process Piping	Seawater Pipeline		Operator Error,					
596	Prudhoe Bay	9/25/06	84.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
130	Endicott	9/26/06	100.0	Flowline	Maintenance Activity	Visually	Valve/Seal Failure,					
248	Prudhoe Bay	9/28/06	185.0	Process Piping			Thermal Expansion,					
52	Prudhoe Bay	10/9/06	336.0	Process Piping	Processing Center		Valve/Seal Failure,					
593	Prudhoe Bay	10/13/06	450.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
129	Prudhoe Bay	10/24/06	50.0	Oil Transmission Pipeline	Operational	Visually	Valve/Seal Failure, Operator Error,	Lack of Procedure/ Policy, Inadequate Procedures/ Policy, Inadequate Implementation of Procedure/ Policy, Poor Oversight of Personnel,	yes	yes		3,500.0
592	Kuparuk River	10/28/06	90.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
591	Prudhoe Bay	11/11/06	1.0	Well			Valve/Seal Failure,					
590	Prudhoe Bay	12/11/06	30.0	Well			Operator Error,					
51	Prudhoe Bay	12/12/06	400.0	Process Piping	Processing Center		Operator Error,					

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589	Prudhoe Bay	12/18/06	35.0	Facility Oil Piping	Well Pad		Erosion, Internal Erosion,					
432	Prudhoe Bay	12/19/06	241,038.0	Storage Tank			Material Failure of Pipe or Weld,					
512	Kuparuk River	1/3/07	165.0	Process Piping	Processing Center		Valve/Seal Failure,					
587	Kuparuk River	1/5/07	440.0	Facility Oil Piping	Well Pad		Operator Error,					
245	Prudhoe Bay	1/7/07	60.0	Process Piping	Processing Center		Thermal Expansion,					
244	Prudhoe Bay	1/13/07	3,249.0	Process Piping	Processing Center		Valve/Seal Failure,					
242	Prudhoe Bay	2/1/07	100.0	Process Piping	Processing Center		Operator Error,					
585	Kuparuk River	2/4/07	481.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
431	Prudhoe Bay	2/9/07	1.5	Facility Oil Piping	Well Pad		Operator Error,					
128	Prudhoe Bay	2/21/07	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
430	Milne Point	3/3/07	2,500.0	Process Piping	Processing Center		Thermal Expansion,					
584	Prudhoe Bay	3/6/07	15.0	Well			Operator Error,					
127	Kuparuk River	3/19/07	105.0	Flowline	Maintenance Activity	Visually	Valve/Seal Failure,					
583	Prudhoe Bay	4/1/07	2.0	Well			Valve/Seal Failure,					
582	Milne Point	4/2/07	38,600.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
580	Kuparuk River	4/15/07	178.0	Process Piping	Processing Center		Corrosion, External Corrosion,					
126	Prudhoe Bay	4/18/07	2.0	Well			Valve/Seal Failure,					
579	Prudhoe Bay	4/26/07	1.0	Well			Thermal Expansion,					
239	Milne Point	5/6/07	56.0	Process Piping	Processing Center		Erosion, Internal Erosion,					
578	Kuparuk River	5/7/07	18.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
238	Prudhoe Bay	5/22/07	434.0	Process Piping	Processing Center		Erosion, Internal Erosion,					
577	Prudhoe Bay	6/3/07	1.5	Well			Material Failure of Pipe or Weld,					
576	Prudhoe Bay	6/23/07	10.0	Process Piping	Seawater Pipeline		Operator Error,					
575	Prudhoe Bay	6/30/07	630.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
574	Prudhoe Bay	7/16/07	2.0	Well			Overpressure,					

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573	Prudhoe Bay	8/1/07	1.0	Well			Valve/Seal Failure,					
123	Colville River, Alpine	9/1/07	1.0	Process Piping	Seawater Pipeline		Valve/Seal Failure,					
71	Prudhoe Bay	9/10/07	880.0	Process Piping	Processing Center		Operator Error,					
234	Prudhoe Bay	10/15/07	1,302.0	Flowline	Operational 3-phase	Odor	Material Failure of Pipe or Weld, Vibration (wind-induced/slugging), Overpressure,	Poor Engineering Design,	yes	yes		31,842.0
233	Prudhoe Bay	10/19/07	75.0	Process Piping	Processing Center		Valve/Seal Failure,					
122	Kuparuk River	10/28/07	250.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
121	Milne Point	11/2/07	75.0	Process Piping	Processing Center		Valve/Seal Failure,					
572	Prudhoe Bay	11/21/07	2.0	Well			Overpressure,					
571	Prudhoe Bay	11/28/07	500.0	Process Piping	Seawater Pipeline		Corrosion, Internal Corrosion, Erosion, Internal Erosion,					
50	Prudhoe Bay	11/29/07	150.0	Process Piping	Processing Center		Valve/Seal Failure,					
570	Kuparuk River	12/1/07	10.0	Process Piping	Seawater Pipeline		Material Failure of Pipe or Weld,					
231	Kuparuk River	12/16/07	4,284.0	Flowline	Operational 3-phase		Corrosion, External Corrosion,					
226	Prudhoe Bay	1/29/08	100.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
225	Kuparuk River	1/30/08	21.5	Facility Oil Piping	Well Pad		Thermal Expansion,					
568	Kuparuk River	1/31/08	120.0	Facility Oil Piping	Well Pad	Visually	Thermal Expansion,					
118	Endicott	2/2/08	20.0	Process Piping	Processing Center		Valve/Seal Failure,					
567	Prudhoe Bay	2/2/08	5.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
117	Prudhoe Bay	2/10/08	1,260.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
566	Prudhoe Bay	2/14/08	150.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
565	Prudhoe Bay	2/18/08	20.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
23	Kuparuk River	2/25/08	4.5	Facility Oil Piping	Well Pad		Thermal Expansion,					
223	Prudhoe Bay	2/26/08	504.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
562	Prudhoe Bay	3/16/08	2.5	Well			Material Failure of Pipe or Weld,					
561	Prudhoe Bay	3/23/08	8.0	Well			Valve/Seal Failure,					

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221	Prudhoe Bay	3/25/08	100.0	Process Piping	Processing Center		Corrosion, Internal Corrosion,					
560	Prudhoe Bay	4/11/08	100.0	Process Piping	Seawater Pipeline		Valve/Seal Failure,					
219	Prudhoe Bay	4/24/08	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
559	Prudhoe Bay	4/27/08	5.0	Well			Material Failure of Pipe or Weld,					
21	Prudhoe Bay	5/8/08	420.0	Facility Oil Piping	Well Pad		Operator Error,					
558	Prudhoe Bay	5/9/08	0.5	Facility Oil Piping	Well Pad							
115	Prudhoe Bay	5/9/08	10.0	Process Piping	Processing Center		Operator Error,					
218	Prudhoe Bay	5/12/08	220.0	Facility Oil Piping	Well Pad	Visually	Corrosion, Internal Corrosion, Thermal Expansion,	Inadequate Implementation of Procedure/ Policy, Lack of Planned Maintenance Program, Poor Engineering Design,	yes	yes		179.0
557	Prudhoe Bay	5/14/08	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
217	Colville River, Alpine	5/17/08	170.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
214	Kuparuk River	5/25/08	10.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
556	Prudhoe Bay	5/26/08	2.0	Well			Material Failure of Pipe or Weld,					
213	Prudhoe Bay	6/2/08	60.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
555	Prudhoe Bay	6/12/08	3.0	Well			Thermal Expansion,					
554	Prudhoe Bay	6/20/08	5.0	Well			Material Failure of Pipe or Weld,					
113	Prudhoe Bay	7/9/08	2.5	Process Piping	Processing Center		Operator Error,					
553	Kuparuk River	7/16/08	850.0	Process Piping	Manifold Building		Valve/Seal Failure,					
552	Prudhoe Bay	7/19/08	2.0	Facility Oil Piping	Well Pad		Operator Error,					
551	Kuparuk River	7/21/08	120.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
208	Prudhoe Bay	7/30/08	520.0	Process Piping	Processing Center		Valve/Seal Failure,					
112	Prudhoe Bay	8/1/08	68.0	Process Piping	Processing Center		Operator Error,					
109	Kuparuk River	8/4/08	120.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					

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110	Prudhoe Bay	8/4/08	10.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
550	Prudhoe Bay	8/9/08	160.0	Well			Material Failure of Pipe or Weld,					
549	Prudhoe Bay	8/19/08	2.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
204	Kuparuk River	8/25/08	50.0	Process Piping	Seawater Pipeline		Corrosion, External Corrosion,					
203	Kuparuk River	9/18/08	0.1	Flowline	Operational 3-phase	Visually	Corrosion, External Corrosion,	Lack of Procedure/ Policy, Lack of Planned Maintenance Program,	yes		yes	2.0
201	Milne Point	9/21/08	1.1	Facility Oil Piping	Well Pad		Operator Error,					
200	Prudhoe Bay	10/2/08	150.0	Well			Overpressure,					
547	Prudhoe Bay	11/3/08	61,626.0	Facility Oil Piping	Well Pad	Visually	Corrosion, Internal Corrosion,	Poor Engineering Design,	yes			34,200.0
108	Milne Point	11/7/08	90.0	Process Piping	Processing Center		Valve/Seal Failure,					
17	Kuparuk River	11/9/08	420.0	Process Piping	Processing Center		Operator Error,					
107	Prudhoe Bay	11/25/08	1.5	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
198	Prudhoe Bay	12/22/08	84.0	Process Piping	Processing Center		Operator Error,					
197	Kuparuk River	12/25/08	94,920.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,					
546	Prudhoe Bay	1/5/09	15.0	Facility Oil Piping	Well Pad		Operator Error, 3rd Party Action,	Inadequate Implementation of Procedure/ Policy,				
416	Milne Point	1/12/09	9,760.0	Process Piping	Processing Center		Thermal Expansion,					
545	Prudhoe Bay	2/1/09	12.0	Well			Material Failure of Pipe or Weld,					
193	Prudhoe Bay	2/18/09	1,932.0	Flowline	Operational 3-phase		Corrosion, External Corrosion,	Inadequate Procedures/ Policy, Poor Engineering Design,				
192	Prudhoe Bay	2/23/09	1.0	Facility Oil Piping	Well Pad		Material Failure of Pipe or Weld,					
191	Prudhoe Bay	2/23/09	18.0	Facility Oil Piping	Processing Center		Valve/Seal Failure,					

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190	Kuparuk River	3/22/09	200.0	Process Piping	Processing Center		Valve/Seal Failure,					
189	Prudhoe Bay	3/30/09	3.0	Well								
543	Prudhoe Bay	4/29/09	20.0	Well								
188	Prudhoe Bay	4/29/09	5.0	Oil Transmission Pipeline	Operational		Thermal Expansion, Valve/Seal Failure,		yes	yes		30.0
542	Prudhoe Bay	5/1/09	1.5	Well								
541	Prudhoe Bay	5/4/09	2.0	Well			Thermal Expansion, Material Failure of Pipe or Weld,					
187	Prudhoe Bay	5/5/09	30.0	Facility Oil Piping	Well Pad		Operator Error,					
185	Prudhoe Bay	5/9/09	3.0	Well			Material Failure of Pipe or Weld,					
540	Prudhoe Bay	5/27/09	40.0	Well			Valve/Seal Failure,					
539	Prudhoe Bay	5/31/09	3.0	Well			Valve/Seal Failure,					
105	Prudhoe Bay	6/6/09	1.5	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
538	Prudhoe Bay	6/8/09	4.0	Well			Valve/Seal Failure,					
184	Kuparuk River	6/14/09	12.0	Facility Oil Piping	Well Pad		Corrosion,					
505	Prudhoe Bay	6/17/09	1.0	Facility Oil Piping	Processing Center							
183	Prudhoe Bay	6/21/09	3.0	Process Piping	Processing Center		Overpressure,					
537	Prudhoe Bay	6/26/09	75.0	Facility Oil Piping	Well Pad		Overpressure,					
182	Prudhoe Bay	7/20/09	420.0	Process Piping	Processing Center		Material Failure of Pipe or Weld,					
181	Colville River, Alpine	7/25/09	70.0	Process Piping	Processing Center		Operator Error,					
535	Milne Point	8/9/09	1.0	Facility Oil Piping	Well Pad		Valve/Seal Failure,					
534	Prudhoe Bay	8/22/09	10.0	Well								
180	Kuparuk River	8/24/09	84.0	Facility Oil Piping	Well Pad		Corrosion, Internal Corrosion,		yes			40.0
104	Prudhoe Bay	9/15/09	0.1	Facility Oil Piping	Well Pad							
412	Prudhoe Bay	10/2/09	3.0	Storage Tank								
533	Prudhoe Bay	10/10/09	5.0	Well								
178	Kuparuk River	10/23/09	18.0	Facility Oil Piping	Well Pad		Corrosion, Material Failure of Pipe or Weld,					
531	Prudhoe Bay	11/8/09	200.0	Well								

NSSA ID	Oil Field	Spill Date	Volume Spilled (gallons)	Regulatory Category	Sub-category	Leak Detection	Primary Cause(s) of Failure	Contributing Cause(s) of Failure	Impacted Tundra	Impacted Frozen Water	Impacted Liquid Water	Square Footage of Tundra Impact
177	Prudhoe Bay	11/16/09	2,000.0	Process Piping	Processing Center		Corrosion, Valve/ Seal Failure,					
176	Prudhoe Bay	11/23/09	10.0	Flowline	Operational 3-phase		Material Failure of Pipe or Weld, Construction, Installation or Fabrication Related,	Poor Engineering Design,				
174	Prudhoe Bay	11/29/09	46,000.0	Flowline	Operational 3-phase	Visually	Thermal Expansion, Overpressure,		yes	yes		8,400.0
529	Prudhoe Bay	12/2/09	7,140.0	Process Piping	Processing Center		Corrosion, Internal Corrosion,					
15	Prudhoe Bay	12/13/09	1,745.0	Facility Oil Piping	Well Pad		Operator Error,					
527	Prudhoe Bay	12/21/09	565.0	Facility Oil Piping	Well Pad	Leak Detection System	Overpressure, Operator Error,	Inadequate Procedures/ Policy, Inadequate Implementation of Procedure/ Policy, Poor Engineering Design,	yes			158,000.0
N=640		**Total=1,200,792.3**										

APPENDIX E

E.1 Expert Panel Member Biographies

Dorian S. Conger, General Manager of Conger & Elsea, Inc. Dorian Conger is an internationally recognized expert in incident investigation, root cause analysis, safety behavior, and human performance. During his more than twenty-five years in business, he has participated in projects or training involving clients in Antarctica, Australia, South America, Asia, Europe, and North America. He has led major investigations at commercial and government facilities including nuclear, manufacturing, chemical, and petroleum. He has conducted training programs involving more than 200 client organizations. He developed the Model Root Cause Analysis and Corrective Action Program that has become the standard for the nuclear and oil industries. Mr. Conger has expertise in safety behavior improvement, corrective action program development and assessment, and incident investigation/root cause analysis. He has a Master's degree (1978) from Purdue University in Organizational Communication (with a minor in Organizational Behavior) and is certified by the Department of Energy as an instructor in Management Oversight and Risk Tree (MORT).

Michael B. Cusick, Director, QA/QC - Americas, CB&I Lummus. Michael Cusick has 34 years of experience in quality and project management for construction and maintenance of oil and gas production infrastructure, including pipelines. Mr. Cusick has expertise in quality development/implementation, inspection, auditing, root cause analysis, risk assessment, welding program/procedure development, ASME piping code stamps, NACE based cathodic protection, and regulatory compliance. Mr. Cusick is Director of quality assurance and quality control for CB&I Lummus with oversight of all North, Central, and South American operations. Mr. Cusick's past Alaska experience includes developing and implementing quality and integrity management programs for BPXA, Unocal, and Alyeska Pipeline Service Company.

Andrew T. Metzger, PhD, PE. Andrew is an Assistant Professor in the Civil and Environmental Engineering Department at University of Alaska Fairbanks. He received his Bachelor of Science in Civil Engineering and Master of Science degrees from Ohio University. Thereafter, he worked in the consulting industry for approximately eight years as a structural engineer and engineer diver. He returned to Academe and completed his Ph.D. degree at Case Western Reserve University. Andrew's dissertation dealt with characterizing the accumulation of fatigue damage in highway bridges. Dr. Metzger teaches courses in structural engineering design and design of engineered systems, in general. He has experience and academic training in risk and uncertainty as applied to engineering practice. A specific example is development of a methodology for prioritizing infrastructure repair work due to mission-risk; based on facility condition.

William R. Mott, Jr., PE, Principal Engineer, Taku Engineering. William Mott has been actively involved in corrosion engineering for the past 23 years. He is a registered Professional Engineer in the State of Alaska, has National Association of Corrosion Engineer (NACE) training in Cathodic Protection and Coating Inspections. He is a member of NACE and the Society for Protective Coatings (SSPC). Mr. Mott has expertise in pipeline cathodic protection design, testing and evaluation; coating engineering; API 653 inspection and repair of above ground storage tanks; and incident investigations. Mr. Mott's Alaska experience includes design and project engineering for Alyeska Pipeline Service Company on portions of the Trans-Alaska Pipeline and the Valdez Marine Terminal, design for LCMF on Barrow Gas Field road crossings, and design and testing of cathodic protection systems for the North Slope Borough village fuel lines.

Shirish L. Patil, PhD. Dr. Patil is a Professor of Petroleum Engineering, Director of the Petroleum Development Laboratory, and Associate Director of Institute of Northern Engineering at the University of Alaska Fairbanks. He holds a Ph. D. in Mineral Resource Engineering and M. S. degrees in Engineering Management, Petroleum Engineering, and Mechanical Engineering. Dr. Patil was a member of the National Academy of Science, Transportation Research Board technical peer-review committee, which reviewed the Proposed Risk Assessment Methodology produced in Phase I of the project. He was selected as the 2005 Alaska Engineering Societies, "Engineer of the Year". He has served as Principal Investigator or Co-Investigator on over twenty research projects related to oil and gas production in Alaska.

E.2 Meetings and Workshops

The Expert Panel met four times over the life of the project: twice in person and twice via teleconference. A record of the Panel's meetings and other information is available on the project website at: http://www.dec.state.ak.us/spar/ipp/ara/nssaexpertpanel.htm

Summary of Meeting
North Slope Spills Analysis
Expert Panel Meeting

April 21, 2010
12:30 PM- 5:00

Expert Panel Member Attendance

Dr. Rod Hoffman (teleconference); Dorian Conger (teleconference); Mike Cusick; Dr. Andrew Metzger; Dr. Shirish Patil; William Mott.

Technical Support Group & Public Attendance

Matt Carr (EPA), Mike Engblom-Bradley (DNR-PSIO), Scott Pexton (DEC), Sam Saengsudham (DEC), Bill Bullock (BP), Ira Rosen (DEC-Project Manager), Larry Hartig (DEC), Melanie Myles (DNR-PSIO), Betty Schorr (DEC), Larry Dietrick (DEC), Rob Guisinger (USDOT-PHMSA), Sandra Pierce-Zimmerman (DNR-JPO), Robin McGee (Conoco Phillips).

Facilitation Team Attendance

Tim Robertson & Amy Gilson (Nuka Research & Planning Group); Leslie Pearson (Pearson Consulting).

Purpose: The purpose of the meeting was to introduce the Expert Panel members and the Technical Support Group, establish the Panel's Charter & Protocols, and present a project overview and methods.

Welcome & Opening Remarks- Larry Hartig, ADEC Commissioner

This project is extremely important to the people of Alaska, our industry and those that have worked for and/or regulated industry over the last 20-30 years. As we look out to the future we'd like to see the pipelines go for another 50-year. There are many challenges to keeping the North Slope pipelines operational. The goal of this study is to identify the risks of keeping pipelines and flow lines operational. The study is not intended to be a "gotcha" for industry. It's intended to provide useful information to the agencies and industry. The project should continue to build a positive reputation of the State of Alaska to explore, produce and transport oil safely. The performance on the North Slope is going to drive future exploration and is critical for Outer Continental Shelf (OCS) development. North Slope spills make national news. A question we'd like answered by this study is are we regulating properly. We're hoping to benefit by having this Expert Panel assist in mitigating the risk of spills.

Brief Project Overview and Schedule- Tim Robertson, Co-Facilitator

The purpose of this briefing is to inform everyone on the project goal, focus and schedule. The goal of this project is to reduce the number and severity of North Slope spills by looking at common causes from past spills and develop recommendations on risk mitigation measures. The following is a link to the project briefing presentation posted on the Expert Panel's website:

NSSA Project Briefing PowerPoint Presentation

Establish the Charge of the Panel through the Charter- Ira Rosen, ADEC Project Manager

We're undertaking a complex and challenging enterprise with the goal to reduce the frequency and severity of spills on the North Slope. You've heard a bit about the importance of this project since the state derives 85% of its income from the oil industry. The original project included looking at the safety of the infrastructure. This project is focused on the environment and protection of the environment, which is DEC's mission and this project is an essential component to improving the mission. We're here today to look at the Panel's role in this project. For our internal discussions, we divided the world into risk assessment and management. The Panel's role is to be a bridge between these two elements. We're looking at the Expert Panel to develop measures and action items to reduce the number and severity of spills. The specific charge of the Panel is to provide recommendations on measures, programs and practices based on common cause of failure and issues related to age related factors. The Expert Panel is not being charged to provide a critic on present and past industry risk programs. The Panel's charter can be found via the following link:

100420 ARA Expert Panel Final Charter

Expert Panel Protocols- Tim Robertson, Co-Facilitator

The Charter was developed by DEC and the Protocols are designed to distinguish between Charter and how the panel will operate as a group. At some point, we anticipate the Panel taking the draft protocol and make them your own. The organizational protocols can be found via the following link:

100331 Draft ARA Expert Panel Organizational Protocols

There are three formal meetings scheduled for the Panel but they are welcome to meet via teleconference or webinar also. Rules of order are up to the Panel. Information that cannot be publically disseminated cannot be brought forward. The final product of the Panel will be recommendations. The Panel will only exist as long life of the project.

Discussion:

Larry Dietrick: We appreciated you working on this project. This isn't a critic of industry. The recommendation you develop can be used by industry and the agencies. After the report is completed each entity will review the recommendation and make a determination on how to move forward in implementing them. Implementation is a key piece that will follow this exercise.

Larry Hartig: We truly want this panel to be independent, we're not trying to steer this project one way or another. Don't be shy. We're putting this in our hands to make the best judgment.

Dorian Conger: On the public announcements we'd be well off to identify one person, whether it's a Panel member or Facilitator. If we have one person, it makes the entire project a lot easier.

Rod Hoffman: It will be important that the Panel members get some soak time with the data. When do you anticipate having data available for your review?

Tim Robertson: We intend on getting the Panel preliminary data by May 18th.

Mike Cusick: Would it be possible to get some preliminary data to begin a review?

Tim Robertson: I'll be showing you some very preliminary data shortly. We'll provide you with periodic updates as the data is collected.

Matt Carr: From an EPA perspective, the Federal side has a lot at stake since our regulations are weak, especially as it relates to flow lines. People are watching from very high levels and asking questions about what is going on up on the North Slope. I anxiously look forward to this analysis and I'm very impressed with the timeline.

Technical Support Group Roles & Resources- Leslie Pearson, Co-Facilitator

Throughout the presentations, you've seen this group mentioned. Across the table from you are representatives from regulatory and resource agencies that have information that may be valuable to this project. In addition to the agencies, there are trade groups or other companies with expertise on a specific topic you may want to access. Panel members can provide us with any recommendations on individuals you may want to have access to, or speak to you and we'll attempt to track them down. We don't have any specific protocols or procedures for communicating with the agencies. If Panel members have specific questions they can be sent to the Facilitators and we'll work with the Technical Support group members and attempt to get your question answered.

Each agency representative attending the meeting provided the Expert Panel members with a brief description of what their agencies responsibilities are, and the type of information they can potentially provide to the project.

Rod Hoffman: The approach we're using with the data makes an unspoken assumption that all the pipelines are of the same material. Does anyone have knowledge of the different alloys and metals are the same?

Mike Engblom-Bradley: Some of the operators used different alloys, I believe Endicott used stainless steel.

Sam **Saengsudham**: Only Endicott has the duplex stainless steel. API 5L is the most common steel requirement.

Mike Cusick: There may not be a lot of data that was collected during the spill. We may want to make a quick list of what we'd like to see today regarding data types.

Rod Hoffman: There may a recommendation made based on what we've heard today of data we'd like to collect in the future.
Bill Mott: We'd be remiss as engineers of not having information on what was tried in the past. We don't want to make recommendations that were tried in the past and failed. Is it an option for use to go back and collect that data?
Leslie Pearson: It may be difficult to collect that data from past incidents given the limited time frame for this project. We are trying to collect additional data from industry to fill the gaps. It's certainly worthwhile to make a list of information/data needs for future studies.
Betty Schorr: We do have reports from industry that have been submitted under the Charter Agreement. All of the reports are posted on line.
Larry Dietrick: In the mid-90's, DEC did it's first analysis on flow lines and recognized the issue of spills from these types of line. We really weren't seeing many spill problems until after peak oil in the mid-90's. The Charter Agreement has a provision that requires an annual report on the state of flow lines—Kuparuk and Prudhoe Bay. Those reports include near misses, wall loss, and a considerable amount of information on the flow lines. In 2004, the problems from flow lines continued and there were some spills of significant volume. DEC then developed regulations via a workgroup to regulate flow lines. In 2006, the GC-2 oil transit line (OTP) spill occurred and we really hadn't seen any problems from OTP's. The federal government does not regulate flow lines. Our regulations came on line and there's been a phase-in implementation approach. The federal government modified their regulations after 2006 as well. Largely the regulatory regimes have changed due to events.
Matt Carr: The EPA has had federal authority since 1972; it's very limited or weak. In the EPA regulations transit lines equal gathering lines, then we have facility piping. Those pipes associated within gathering centers and modules. The state and EPA have different definition such as oil. The state categorized process water as a hazardous substance. The federal government lumps—process water is oil.

Preliminary Results & Methods for the Analysis- Tim Robertson, Co-Facilitator

The purpose of this presentation is to layout where we are today. It's very fluid and provisional but we want to show you where we're at when we started this project in mid-February. The data is being validated, we're still collecting data and the methods are draft and we're open to suggestions.
The following is a link to the PowerPoint presentation on preliminary results & methods for the analysis of data associated with North Slope spills:

NSSA Preliminary Results and Methods PowerPoint Presentation

The first task will be to inform everyone on the quality and completeness of data. We're dealing with lack of data and variability of the type of data.
Mike Cusick: It concerns me if we are going to just look at age. We need to add the maintenance and monitoring activities into the equation. We can't just look at the data based on age as a factor.
Melanie Myles: There is data in the Charter report where you can extrapolate a change in mitigation measures because of a spike in spills.
Rod Hoffman: Will the operators have a change to review the draft recommendations?
Ira Rosen: This is an issue we've wrestled with. Originally we invited industry to have members on the Panel. We took a step back and at this point we've invited operators to have a member on the Technical Support Group. We haven't received confirmation that the operators will fulfill the role. The answer to that question is, we hope so.
Rod Hoffman: I believe we heard two things that may be incompatible. One was the heightened interest in the project and the other was the limitation of the data.
Mike Engblom-Bradley: Incident investigation has improved in recent times.
Dorian Conger: I'm assuming the panel can make recommendations for better data collection, am I wrong?
Rob Guisinger: I believe we do require a root cause analysis for every spill; it may be part of the integrity management requirements.
Mike Cusick: The federal requirements require that the operator would have to do a risk assessment, not specifically a root cause analysis.

Expert Panel Discussion and Input on Analysis Methods

Dorian Conger: You should proceed with the data analysis plan. How long will it be before you can provide data to us?

Tim Robertson: by the end of next week, we should be able to provide a preliminary analysis to you. The big first step will be to perform a gap analysis too.
Dorian Conger: We should have a discussion after the initial analysis is completed. Perhaps we should schedule a conference call in 2-weeks. Then we could have a more productive discussion.
Shirish Patil: Do you have anything more than what is in your presentation on the method? My concern is that industry will not provide the necessary data and our analysis will be incomplete. My second concern is related to a topic raised by the Commissioner and that's the revenue stream. If you shut in a field it's going to have an impact.
Ira Rosen: The original scope of the study specifically excluded any down-hole impact. We have kept seawater spills in the scope because of the importance to the reservoir.
Rod Hoffman: We're going to make some big assumptions to reach a conclusion. We may not have much knowledge on where they've replaced sections. Industry can certainly muster themselves to comment on the assumptions. I doubt the data will be good enough to make recommendations without assumptions.
Bill Mott: Do we make those assumptions or should we go back to industry and ask for more data?
Rod Hoffman: From the industry side we purposely left the descriptions at a high level because we didn't want the regulators to tell us how to run the fields.
Mike Cusick: We may have to use scenario-based assumptions to develop our recommendations.
Rod Hoffman: I know the database is not going to provide us with the level of information we need. We will have to use scenarios. I have no doubt that one of the recommendations will be to gather better data.
Mike Cusick: Are we going to make recommendations to the regulators, as well as industry?
Rod Hoffman: The EPA regulatory definition for the SPCC plans. The plans never go to EPA, there's no rigid description of what a facility is and if you broke the field out into smaller facilities the plans won't have to be reviewed very often.
Mike Cusick: We may want to talk about the mechanics of how we want to interact, the mechanics and facilitation of this project. I'm use to working on things in a collaborative manner electronically.
Ira Rosen: One thing we should discuss is how you want to interact with the Technical Support Group. One thought was that we have them readily available to discuss/answer questions. Industry hasn't exactly bought into the concept and would rather observe.
Dorian Conger: If their not willing to be fully engaged then they need to accept the results.
Ira Rosen: I characterize your sessions as being work sessions.
Rod Hoffman: Industry didn't send anyone that can commit or speak or today. If we have questions for industry then we need to submit them in writing ahead of time.
Ira Rosen: The responses that we would receive back may introduce bias since they won't be responding with anything negative back to us. We will communicate that the data set is limited and you'll have to make assumptions. I would much rather forward a loosely defended, low priority mitigation measure rather than leave it off the table.
Rod Hoffman: If we can put the North Slope in perspective to the Gulf of Mexico is certainly a different story than the current public image. Once we get the data will help us begin to start writing and put things together. I don't think we need a chair.
Consensus was reached that a chair is not necessary for the Expert Panel.

Review of Action Items

- ☐ Provide a summary of the risk mitigation measures submitted by the general public from Phase 1 of the risk assessment.
- ☐ Post the Charter Agreement reports and presentations on the Expert Panel website.
- ☐ Establish an electronic document (Google doc) for the Expert Panel members to begin writing ideas on a collaborative manner.
- ☐ Provide a preliminary data and gap analysis to the Panel by April 30th.
- ☐ Provide State/Federal Congressional testimony from 2006 spills to Expert Panel
- ☐ Provide a list of the individuals on the Technical Support Group.

Schedule Next Meeting

May 6, 2010 at 10:00AM ADT-Expert Panel Webinar

Summary of Meeting
North Slope Spills Analysis
Expert Panel Meeting
May 6, 2010
10:00 AM- Noon ADT

Expert Panel Member Attendance

Dorian Conger, Mike Cusick, Dr. Andrew Metzker, William Mott.

Facilitation & Project Team Attendance

Ira Rosen (DEC), Tim Robertson, Amy Gilson, Elise DeCola, Tom Miller, Brett Higman (Nuka Research & Planning Group), Leslie Pearson (Pearson Consulting).

Purpose: The purpose of the meeting was to review and discuss the data gap, data collection status, preliminary data analysis and methods.

Data Gap Analysis & Discussion (T. Robertson/L. Pearson)

Data Gap Analysis/Completeness Matrix (Excel file)

The gap analysis is intended to look at what data we had as it applies to Flow Lines and Oil Transmission Pipelines. The percent completeness represents where we had data for each variable. After spill data and immediate cause the completeness drops off significantly. The data represents what was collected from the spill files, corrosion reports, C-Plans and contacting individuals. We're hoping to improve upon this since it doesn't reflect what we've received from the operators. The process we've been using to obtain information from the operators is the data collection form. Our researchers attempt to fill in as much information as possible and we're asking the operators to fill in the gaps as well as validate the information we have collected. All of the forms have been sent to the operators. Today we're meeting with BP to review and validate the information provided and also fill in any data gaps. BP has a very good spills database but it's not married to their integrity management database. Our understanding is that they are looking at a way to marry the two together. The data that's coming in from the operator will be incorporated into the database.

In addition to the operator data, we're trying to determine when an individual pipeline had come into service. We'd like to be able to calculate the age at failure. Another piece of information we're reviewing is the leak rate so we can calculate leak rate per mile, per field. The last piece of data we've been trying to establish is a geospatial tag. We'd like to be able to tag the leak to a pipeline or rack of piping. In order to maintain the schedule, we essentially need to wrap up the collection by next week so we can provide you with preliminary analysis by May 20th.

Our impression is that we know a lot less than what we wanted to capture. The question is do we have enough data to proceed or should we attempt to work more with the operators. The data collection phase will have to be completed by next week in order to come to the June meeting prepared. We're still proceeding with June 30th as the end date for this project. We'll need to articulate the argument if we need additional time. It's not clear how much additional data we'll actually be able to obtain from the operators if we did extend the deadline. We'll need to qualify our recommendations with a statement regarding the lack of data available. The lack of data may limit the strength of recommendations. There will certainly be a recommendation for the ADEC to improve their data collection method in the future if they intend on doing similar studies.

Preliminary Data Analysis & Discussion (B. Higman)

Presentation was made on the preliminary data such as: spill volume by year, oil field, and regulatory categories. The Excel file can be accessed via the following web link:

100501 All Cases Plus Analysis (Excel file)

For primary cause data there's a number of unknowns. It may be fine to remove the unknowns from the data set and it wouldn't effect our conclusion, especially if there's no significant change in the volume spilled.

<u>Andrew Metzker:</u> It would be beneficial to looking at volume for fitness failure type. It would be interesting to know on average which failure mode results in the largest spills

<u>Mike Cusick</u>: If we get the analysis requested by the others that would be good for me.

Dorian Conger: We've got the categories based on spill size, if we can capture the data for the type A-B-C spill that may give us some interesting information-size bin plotted by primary cause. It would be good to see the similarities and also distribution by field.
Bill Mott: I'm the more data guy of the group. If there's any way to gather additional information—coating, non-coating, welds, pig data.
Tim Robertson- We will have a conversation with the operators to obtain additional information. We can use production volume as an indicator of velocity. That is something we're looking at.

Draft Report Table of Content & Discussion (E. DeCola)

100505 Draft Table of Content for the NSSA Final Report

The table of content is essentially an outline of the final report. We'd like to make sure that the table of content is the proper approach for the Expert Panel. There are a few other reports associated with this project but this table of content focuses on the North Slope Spill Analysis.

Review of Action Items

- ☐ Provide a more complete data analysis to the Expert Panel by May 20th for review prior to the June 2-4 meetings.

Schedule Next Meeting

June 2-4th in Anchorage, AK

E.3 Charter and Organizational Protocols

North Slope Spills Analysis
Expert Panel Charter

The purpose of this charter document is to create the Expert Panel for the Alaska North Slope Spills Analysis and establish their charge.

Goal and Objective

The goal of this process is to reduce the number and severity of future spills from the Alaska North Slope oil pipelines by providing recommendations on appropriate risk reduction measures to address common causes of failures of this aging infrastructure.

This independent panel has been selected based on their demonstrated knowledge in one or more of the following areas:

- General knowledge of crude oil production operations and measures used to
    - Inspect for aging conditions
    - Detect leaks
    - Prevent leaks and spills
- Knowledge of loss-of-integrity root cause investigations and common cause analysis
- Knowledge of analysis of leak data and general engineering practices

An analysis of reported spills resulting from leaks of production fluids from the North Slope pipelines will be presented to the Expert Panel to establish the common causes, frequencies, and trends of failures in this aging infrastructure.

The objective of the Expert panel process is to provide an independent review of the analysis and develop consensus recommendations on appropriate risk reduction measures to address the results of the analysis.

Charge

The charge of the Expert Panel is to provide recommendations on measures, programs, and practices to monitor and address common causes of failures identified in the analysis of spill data. These recommendations should focus on issues associated with the age-related factors.

The Expert Panel is **not** being charged with providing a critique of past or present integrity management and spill mitigation programs on the North Slope.

Roles

Project Manager: *The Alaska Department of Environmental Conservation (ADEC) is managing this project. The ADEC Project Manager is Ira Rosen. The Project Manager has convened this independent panel, based on recommendations of the Project Team.*

Project Team: *A team consisting of ADEC staff and their contractor (Nuka Research and Planning Group, LLC.) is conducting the data collection and analysis of North Slope Pipeline Spills.*

Expert Panel: *Six independent professionals have been selected to provide recommendations on risk reduction measures to address the common causes of leaks from the aging oil production infrastructure.*

Facilitation Team: *Nuka Research and Planning Group, LLC.) is facilitating the expert panel process. They will chair the meetings of the panel and provide assistance with organization, agendas, meeting records, communications, and travel.*

Technical Support Group: *Representatives of organizations with specific knowledge of the North Slope oil production operations, governing regulations, and applicable standards have been asked to provide information, briefings, or presentations to the Expert Panel as needed. The Technical Support Group members will be nonvoting participants in the meetings.*

Responsibilities

It is the responsibility of the Expert Panel to provide independent recommendations on mitigation measures, programs, and practices to monitor and address common causes of failures identified in the analysis of spill data. The Panel will strive for consensus in their recommendations.

The Technical Support Group is responsible for providing factual information to support the deliberations and decisions of the Expert Panel

Governance

The Expert Panel and Technical Support Group will operate under a set of Protocols drafted by the Project Manager and approved by the Expert Panel.

Meetings

The Expert Panel and Technical Support Group will meet approximately three (3) times between April and June of 2010. A tentative meeting schedule has been established. All meetings will be held in Anchorage, Alaska.

- Panel orientation and overview: April 21, 2010
- Work session to review North Slope spills analysis and develop mitigation measure recommendations: June 1-3, 2010
- Final meeting to review and approve final report: June 24, 2010

Panel members will be provided with review copies of all analyzes and discussion documents two (2) weeks prior to all scheduled meeting dates.

Since the meetings will be deliberative work sessions to develop a work product for the State of Alaska, they will not be open to the public. The Expert Panel may also choose to conduct some sessions without Technical Support Group present.

Records

All records of the Expert Panel will be preserved as public record.

The Facilitator will prepare meeting summaries. Draft summaries will be provided to the Expert Panel members within one week after a meeting for review prior to finalizing. The Facilitator will maintain and post on the Expert Panel website agendas, handouts, and meeting summaries.

Compensation

Expert Panel positions are voluntary appointments, however they will be provided with a reasonable honorarium for their services. All necessary travel expenses, meals, and lodging will also be provided.

Termination Date

The Expert Panel and Technical Support Group will exist only during the life of the project, which will conclude on June 31, 2010.

Amendments

Amendments to this charter of the North Slope Spills Analysis Expert Panel require the approval ADEC Project Manager.

North Slope Spill Analysis
Expert Panel
Draft Organizational Protocols

These purpose of these protocols are to establish the standards of conduct for the Alaska North Slope Spill Analysis Expert Panel. These Protocols are to be approved by the Expert Panel.

Membership The Expert Panel will consist of six voting members chosen by the ADEC Project Manager. Any member may withdraw from the panel at any time without prejudice. The Project Manager may then appoint another panel member to fill the vacancy.

Interest Represented

Panel members have been chosen based on their background and subject matter expertise. They were not chosen to represent any organization or stakeholder group. The charge of the Expert Panel is to utilize their expertise to develop recommendations on measures, programs, and practices to monitor and address common causes of failures identified from the analysis of Alaska North Slope spill data.

Members agree not to advocate for any constituency, company, organization, or stakeholder group, but to represent only the interest of addressing the charge given to the panel.

Decision Making

The Expert Panel will operate by consensus. Panel recommendations will be made by the unanimous concurrence of all members. However, discussion on items where consensus cannot be reached will be documented in the final report. Panel members agree to make a good faith effort to work toward consensus with other members.

Members of the Technical Support Group do not have a vote in the recommendations of the Panel.

Public Announcements

Members agree not to report opinions expressed in meetings, nor shall they report independently on Panel action. Any public announcements will be agreed upon by the Panel and distributed to the public through the Facilitators.

Attendance and Quorum

Each Panel member agrees to make a good faith effort to attend each session of the Panel. Attendance by teleconference will be allowed, but is not preferred. A quorum for the conduct of business at each meeting shall be a two-thirds majority of the Expert Panel members. Technical Support Group attendance shall not be counted towards a quorum. The Facilitator will keep a record of attendance for all meetings, including teleconferences. Attendance will be published with the meeting summaries.

Meetings

The Expert Panel and Technical Support Team will meet approximately three (3) times between April and June of 2010. A tentative meeting schedule has been established. All meetings will be held in Anchorage, Alaska. Additional information about meeting times and location will be posted on the Expert Panel website and updated by the Facilitator.

- Panel orientation and overview: April 21, 2010

- Work session to review North Slope spills analysis and develop mitigation measure recommendations: June 1-3, 2010
- Final meeting to review and approve final report: June 24, 2010

If necessary, interim meetings can be called by the Project Manager or by a simple majority of the Panel members and can also be held by teleconference, electronic mail, or by other means.

Since the meetings will be deliberative work sessions to develop a work product for the State of Alaska, they will not be open to the public. The Expert Panel may also choose to conduct some sessions without Technical Support Group present.

Rules of Order

The Facilitator will chair all meetings and call upon speakers.

An agenda of each meeting will be posted prior to the meeting. The agenda will be adhered to unless a two-thirds majority of the attending panel members vote to add, delete, or table an issue on the agenda.

Expert Panel members will receive priority to speak about any topic. Speaker order will be determined by rotation. Technical Support Group members will speak when scheduled on the agenda and when requested to do so by a Panel member. Parties other than the Project Manager, Facilitators, Expert Panel, and Technical Support Group will not be allowed to speak at the meeting unless a two-thirds majority of the attending Panel Members vote to allow.

Personal attacks and prejudiced statements will not be tolerated.

Information.

All members of the Expert Panel and Technical Support agree not to withhold relevant and non-proprietary information. All parties agree not to divulge information that cannot be included in the meeting summaries and which is shared by others in confidence. Information and data provided to the Panel, either orally or in writing, is a matter of public record.

Records

The Facilitator will prepare meeting summaries. Draft summaries will be provided to the Expert Panel members within one week after a meeting for review prior to finalizing. The Facilitator will maintain and post on the Expert Panel website agendas, handouts, and meeting summaries.

Recommendations

Panel recommendations will be submitted in a written report to the Project Manager. The report will include both recommended measures and justification for the recommendations. The Facilitator may assist the Panel in drafting the report.

Adjournment

After all the items on the agenda have been dealt with, the Facilitator will ask for a motion to close the meeting and ask for a second. If there is a protest the attendees may vote (two-thirds majority) to continue the meeting until the protested issue is resolved.

Amendments

Amendments to these Protocols require the unanimous concurrence of the Expert Panel.

Adopted on April 21, 2010

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APPENDIX F

F.1 Recommended Root Cause Analysis Spill Investigation Guidelines

Developed by Dorian Conger.

The object of a Spill Investigation is to identify facts, not fault. Identifying facts will help:

- describe what happened, when, and where?
- determine the actual and potential loss(es)
- determine the root causes
- determine the risks
- develop controls to reduce the risk of recurrence
- define trends
- demonstrate concern
- allow for communication of "lessons learned"

It is important to identify the facts and root causes of all spills as soon as possible after an incident occurs. When considering the circumstances leading to the spill, special attention should be paid to the severity or potential severity of the spill results. Figure 1 is a matrix that was developed to assist in classifying the spill and provides a guide for completing the investigation. The spill scene should be secured and preserved immediately after the incident, to aid the investigation. Interviews should be conducted and written statements obtained while the spill is still fresh in the witnesses' memories.

It is the Supervisor's responsibility to manage the response to the spill and notify the appropriate agencies. The Supervisor must decide whether to investigate the spill himself, assign another individual or form a team to investigate. If the investigation is to be conducted by an individual, the individual should have received training on the analytical techniques or "tools" of cause analysis. If the investigation will be performed by a team, the team should be comprised so that at least two members have been trained using these "tools". A team is recommended for investigating all C and D classification incidents. An investigation team should work under a written charter that will identify the scope, resources and desired outcome of the investigation.

Series of Analytical Techniques

The following five techniques, rank ordered from top to bottom in terms of their complexity and completeness, are incorporated into incident investigation training. Proper application of these techniques will facilitate identification of root causes and effective corrective actions. Training should be provided to anyone who will be using these techniques to ensure proper application.

Change analysis

Hazard-Barrier-Target Analysis

Fault Tree analysis or Failure Modes and Effects Analysis

Events and Causal Factors analysis

Management Oversight and Risk Tree (MORT) Analysis

Other systematic formal recognized analytical methods may be used for root cause analysis.

Collection of information

Some of the equipment that may be useful in gathering information include, a camera, a measuring tape (100 ft.), plastic flagging tape (to cordon off the area), tags for identifying equipment or evidence, note pads and various colored pens or pencils, graph paper for sketches and a flashlight with spare batteries. If a video camera is available, it could be useful in recording the evidence at the scene. (Cameras are not always intrinsically safe, be sure to contact the Supervisor on location about the proper use of cameras.)

Examine the scene of the spill carefully to ensure all the physical evidence is gathered and/or recorded as it was at the time of the incident. This may include measuring distances and sketching on graph paper when possible. Pictures should be taken of the overall scene, each piece of equipment and other evidence. A log of the pictures should be kept for future reference.

When interviewing witnesses, ensure they understand that the reason for the interview is to determine facts, **not to find fault**. When questioning witnesses, the investigator should try to ask open ended questions. Ask people to explain in their own words exactly what took place. Good interview notes are essential for documenting facts. Take notes carefully.

Diagrams, drawings and maps should be gathered and used in conjunction with other information to assist in assembling a time-line (events and causal factors chart) of the incident. The time-line should be put together from the information presented and should give an idea of **Who** did **What, When and Where**.

All tools and equipment should be examined carefully for excessive wear or failure.

There may be situations where an independent firm may be engaged to confirm exactly how a piece of equipment failed.

Analyzing Information and making Recommendations

Once the facts have been gathered, the information must be analyzed to identify the root cause(s) and the most feasible corrective action. It is important to cross check all data sources to make sure all "facts" have been discovered and any inconsistencies are resolved. All conclusions and/or recommendations must be supported by the facts. Applying the "Precedence Sequence" will help to identify the most cost effective and advantageous recommendations. The Precedence Sequence ranks the effectiveness of various approaches to preventing mishaps.

Precedence Sequence

1. Design for Minimum Hazard
2. Safety Devices
3. Safety Warnings
4. Procedures
5. Training and Awareness
6. Notify Management of Risk and Accept Situation Without Corrective Action

Good cause analysis programs embody this sequence. If the Precedence Sequences are rank ordered in terms of their likelihood to prevent recurrence of mishaps, they rank order from top to bottom. They're also rank ordered from top to bottom in terms of how much money they usually cost. Corrective actions can be compared to it. "We had a high risk failure. Are we doing anything on the top end of the PS to prevent its recurrence?" Most of the corrective actions are at the 4, 5 or even 6 level, which is often inappropriate.

Corrective Action

Corrective action for minor spills should be addressed by the Supervisor. The Supervisor has the responsibility for ensuring that corrective action is implemented.

The Supervisor may contact the E&S Representative or Business Unit ES&H Group for assistance. When a team performs the investigation, the team may make recommendations to the Process Owner. The responsibility for ensuring that the corrective action is implemented may return to the Supervisor through the Process Owner.

For all of category C and D, an extent of condition evaluation, an extent of cause evaluation, a management system, organizational, and programmatic evaluation shall be performed.

For all category C and D evaluations, an effectiveness review plan shall be developed and presented that measures the effectiveness of the implemented corrective actions to prevent recurrence over a specified period of time.

Reporting and Follow-up

Once the causes have been determined and corrective action(s) identified, important information needs to be shared.

When the incident is minor (Class A or B) the corrective action can be determined and decided upon by the Operations Supervisor. Follow-up is the responsibility of the supervisor and can be delegated to other employees.

The more significant incidents (Class C or D) may require a team to review root causes and recommendations prior to implementation of corrective action. Team findings need to be reported to the Process Owner that requested and chartered the investigation team. The Process Owner who requested the investigation is responsible for assigning the follow-up responsibility. The scope of follow up activities should enable the Process Owner to verify completion and the effectiveness of corrective actions.

The Process Owner is responsible for providing the E&S Representatives a copy of the investigation findings for distribution. The E&S Representatives have the responsibility to relay information obtained from a spill investigation, which occurs in their Profit Center (PC), to the other PC E&S Representatives and the Business Unit ES&H Group. The Business Unit ES&H Group has the responsibility to pass the information to other Operating Companies, Corporate Headquarters, and other service groups here in the Business Unit.

Figure 1. Cause Process Elements.

INCIDENT CLASSIFICATION	CATEGORY	PEOPLE (RESOURCES) INVOLVED	USEFUL TOOLS	ESTIMATED COMP. TIME
A	Spills of less than 55 gallons	Supervisor (May delegate in Field Safety Committee Safety & Environmental Reps.)	- Change Analysis - HBT - Others as needed (Fishbone, Contingency Diagram, STOP Cards)	1-2 Days
B	Spills of 55 – 99 gallons	Field-Based Team (Size Membership determined by Operations Supervisor)	- Change Analysis - HBT - Fault Tree - Others as needed	5 Days
C	Spills of 100 – 999 gallons	FMT-Based Team (Should consist of Field Office & external FMT Member(s) or BU	- MORT (Partial) - Events & Causal Factors - Others as Needed	2-3 weeks
D	Spills of 1,000 gallons or more	Multi-Disciplined Team (i.e. +/-4 Team Members)	- MORT (All or Partial) - Events & Causal Factors - Others as needed	4 Weeks

F.2 Risk Informed Spill Categories

Qualitative Consequence

- CATASTROPHIC - Loss of system or plant, such that significant loss of production, significant public interest or regulatory intervention occurs or reasonably could occur.
- CRITICAL - Major system damage or other event which causes some loss of production, atffects more than one department/facility, or could have resulted in catastrophic consequences under different circumstances.
- MARGINAL - Minor system damage, or other event generally confined to one pipeline/ facility.
- NEGLIGIBLE - Less than the above.

Qualitative Probability

- FREQUENT - Likely to occur often during the life of an individual component, pipeline or system or very often in operation of a large number of similar pipelines/facilities.
- PROBABLE - Likely to occur several times in the life of an individual component, pipeline or system or often in operation of a large number of similar pipelines/facilities.
- OCCASIONAL - Likely to occur sometime in the life of an individual component, pipeline or system, or will occur several times in the life of a large number of similar pipelines/facilities.
- REMOTE - Unlikely, but possible to occur sometime in the life of an individual component, pipeline or system, or can reasonably be expected to occur in the life of a large number of similar pipelines/facilities.
- IMPROBABLE - So unlikely to occur in the life of an individual component, pipeline or system that it may be assumed not to be experienced, or it may be possible, but unlikely, to occur in the life of a large number of similar pipelines/facilities.

Qualitative Risk Matrix

PROBABILITY/ CONSEQUENCES	CATASTROPHIC	CRITICAL	MARGINAL	NEGLIGIBLE
Frequent	HI A	HI A	HI A	MOD LO C
Probable	HI A	HI A	MOD HI B	MOD LO C
Occasional	HI A	MOD HI B	MOD LO C	LO D
Remote	MOD HI B	MOD HI B	MOD LO C	LO D
Improbable	MOD LO C	MOD LO C	MOD LO C	LO D

Risk Informed Root Cause Program Elements

RISK CAT.	TEAM	RELATION TO SITUATION	LENGTH	REVIEW TYPE	ANALYTICAL TECHNIQUES	ANALYSTS AND TEAM LEADERS TRAINING
A	Team Inter-discipline	Indep.	30 days	Indep.	MORT & E&CF, others as needed	Event Investigation Workshop 5 - 7 days
B	Team Inter-discipline	Mixed	10 days	Indep.	MORT & E&CF, others as needed	Event Investigation Workshop 5 - 7 days
C	Individual	Line	24-32 hours	Indep.	E&CF & Change, HBT, LPS, TapRoot or Fault Tree	Problem Anal. Workshop 2 ½ - 3 days
D	Individual	Line	2-4 hours	Indep.	None Required, Change, HBT, LPS, TapRoot or Fault Tree as needed	Problem Solving Session 1 - 2 days

APPENDIX G

G-1. Production Statistics from North Slope Oil Fields

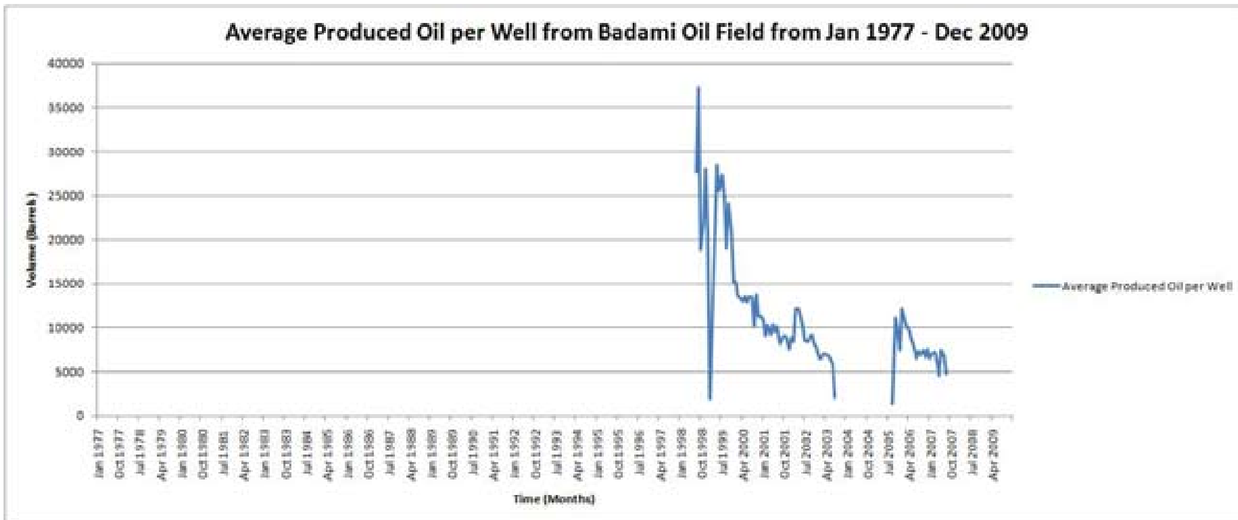


Figure G-1 Average volume of oil produced per well from the Badami Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

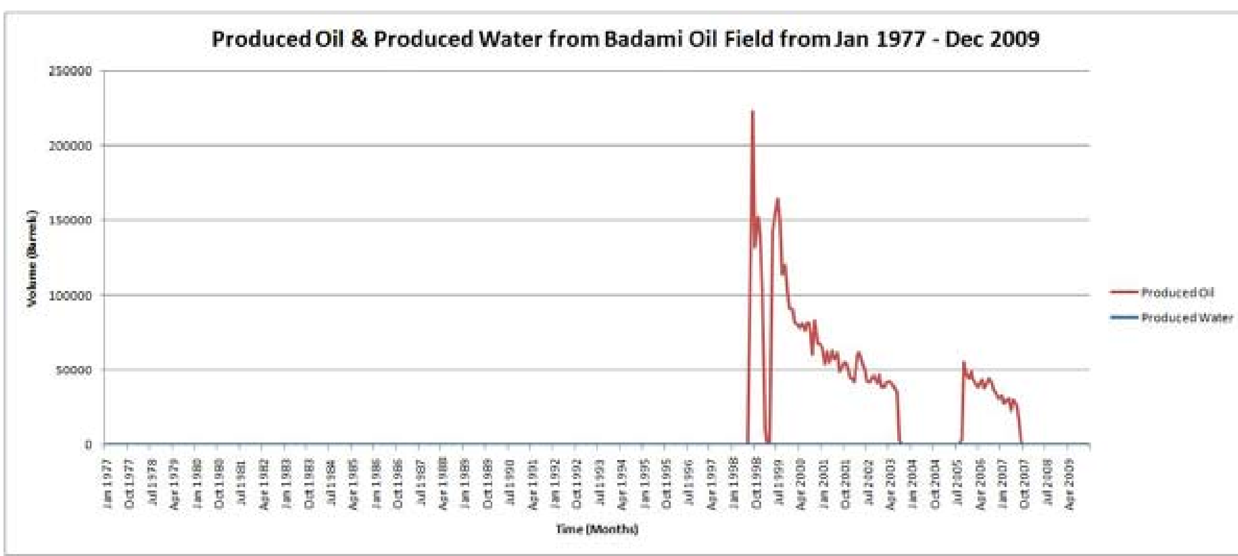


Figure G-2 Total monthly volume of produced oil and produced water from the Badami Oil Field from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission. Produced Oil is shown in red, Produced Water is shown in blue.

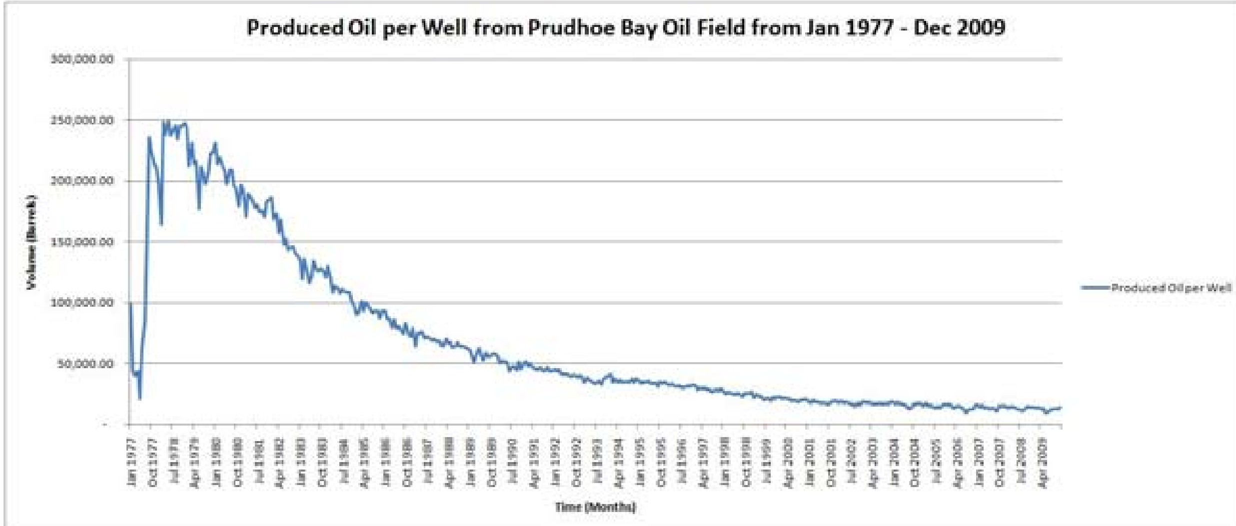


Figure G-3 Average volume of oil produced per well from the Prudhoe Bay Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

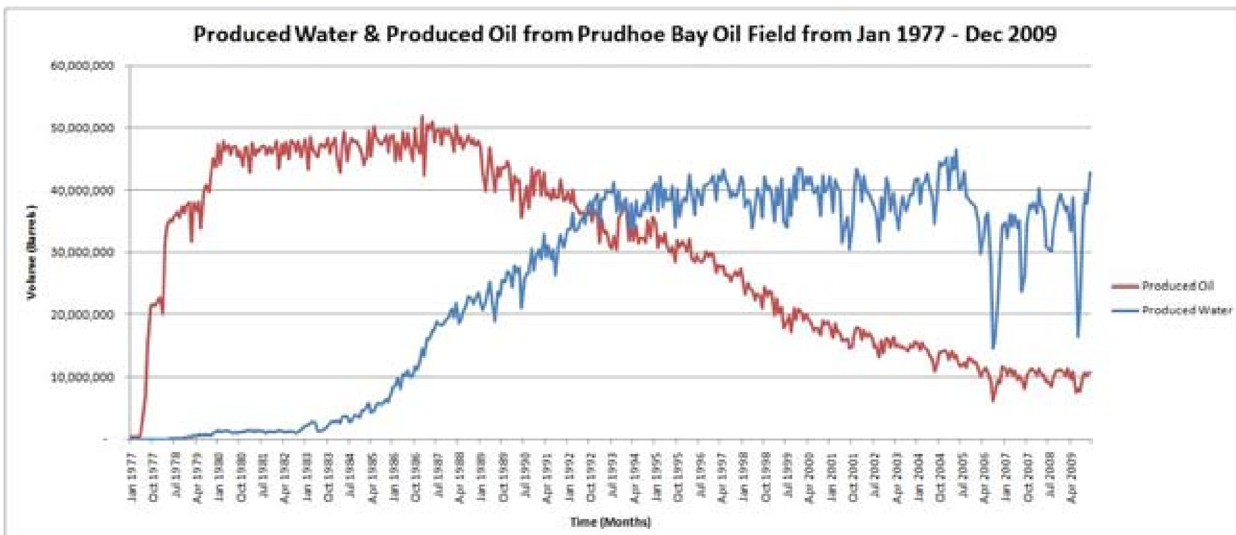


Figure G-4 Total monthly volume of produced oil and produced water from the Prudhoe Bay Oil Field from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission. Produced Oil is shown in red, Produced Water is shown in blue.

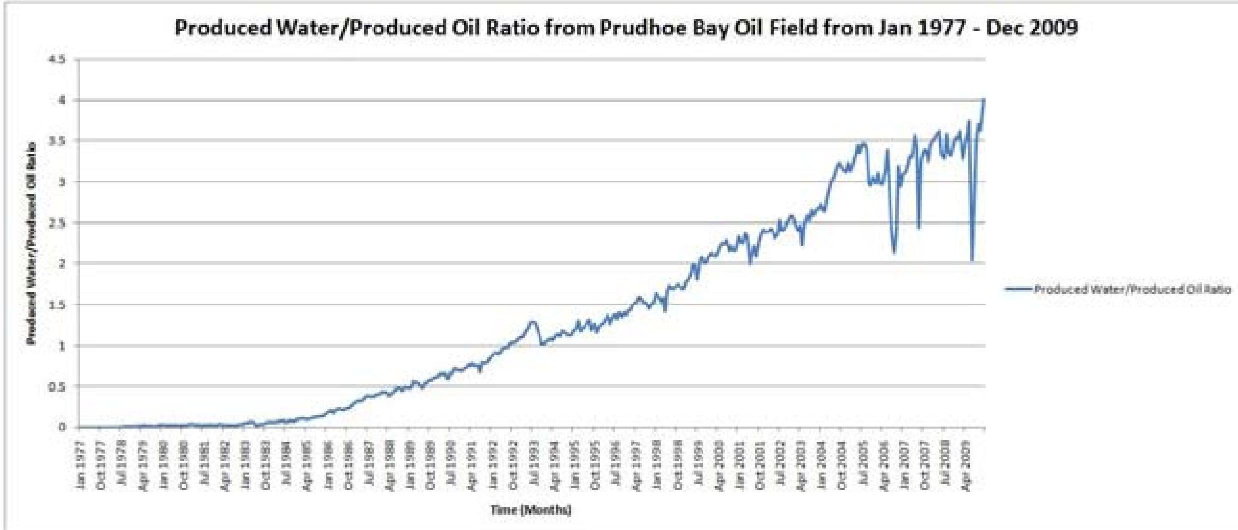


Figure G-5 Ratio of produced oil and produced water from the Prudhoe Bay Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

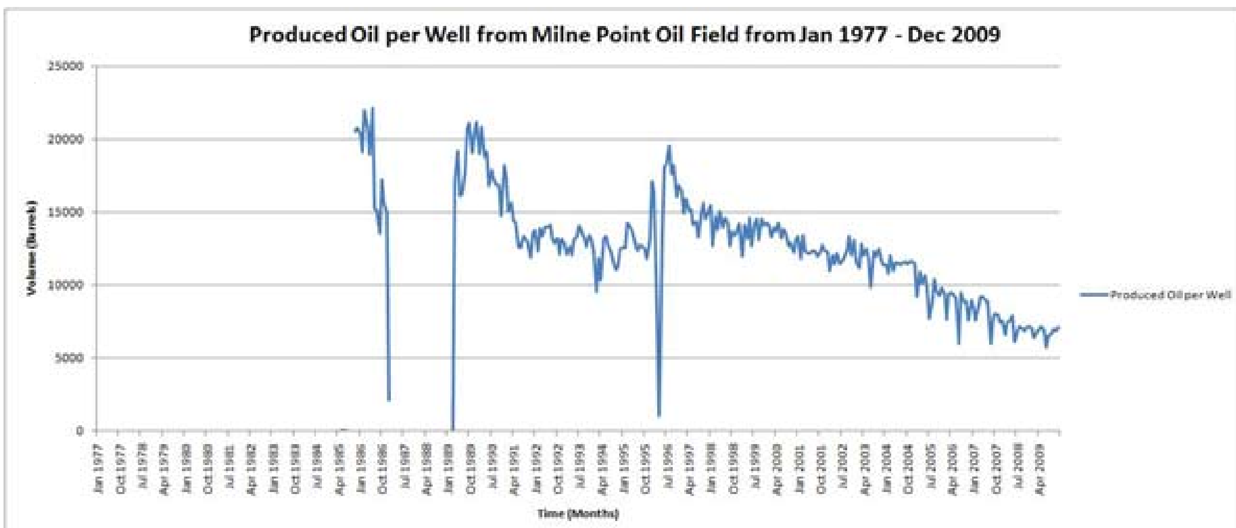


Figure G-6 Average volume of oil produced per well from the Milne Point Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

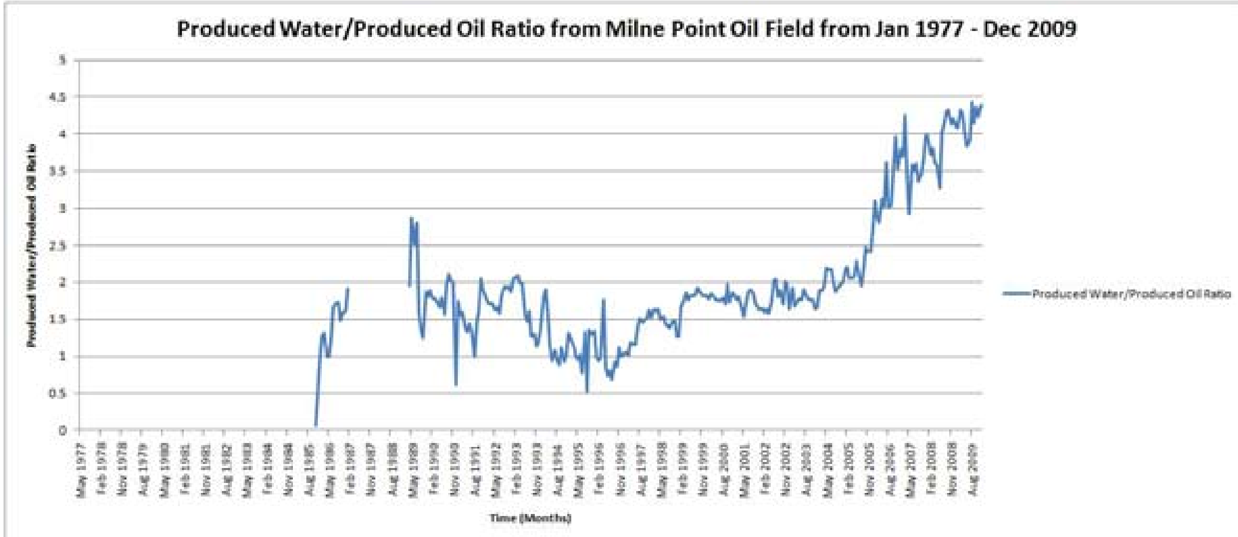


Figure G-7 Ratio of produced oil and produced water from the Milne Point Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

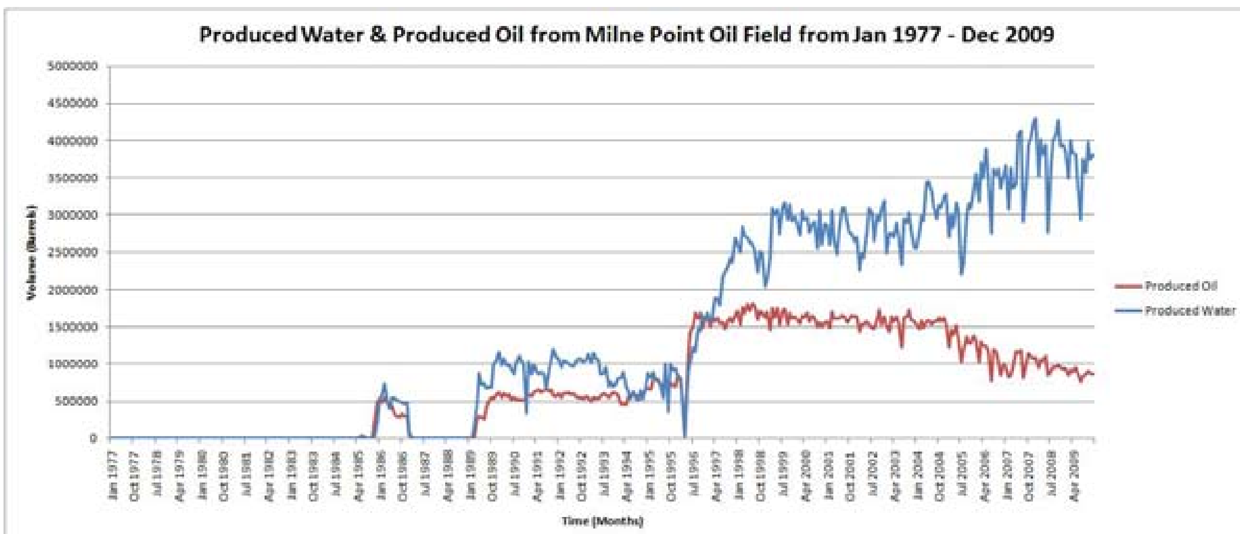


Figure G-8 Total monthly volume of produced oil and produced water from the Milne Point Oil Field from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission. Produced Oil is shown in red, Produced Water is shown in blue.

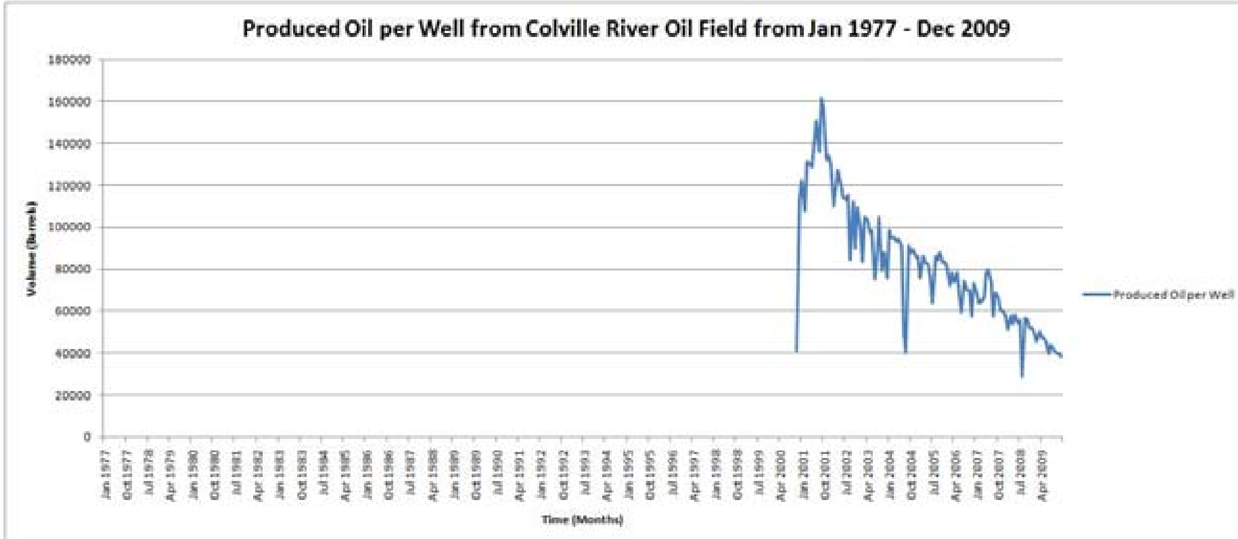


Figure G-9 Average volume of oil produced per well from the Colville River Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

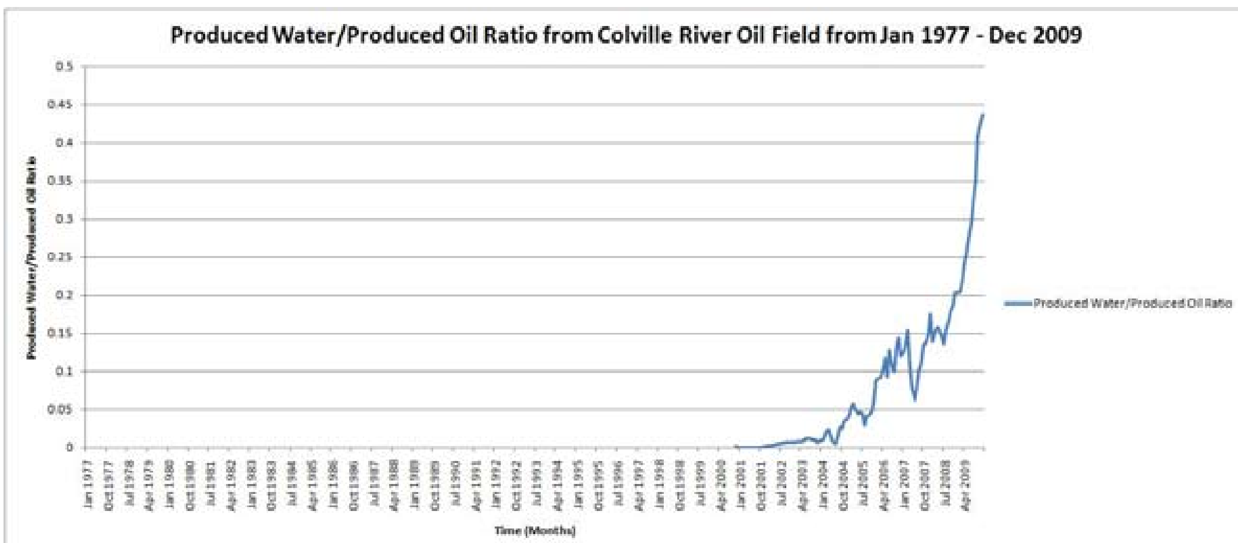


Figure G-10 Ratio of produced oil and produced water from the Colville River Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

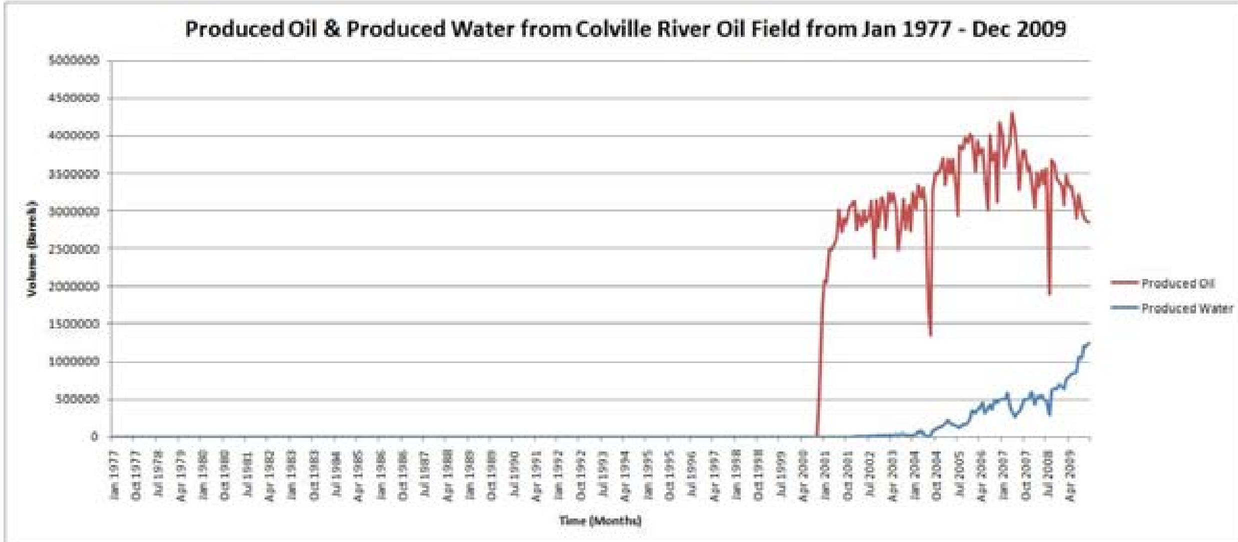


Figure G-11 Total monthly volume of produced oil and produced water from the Colville River Oil Field from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission. Produced Oil is shown in red, Produced Water is shown in blue.

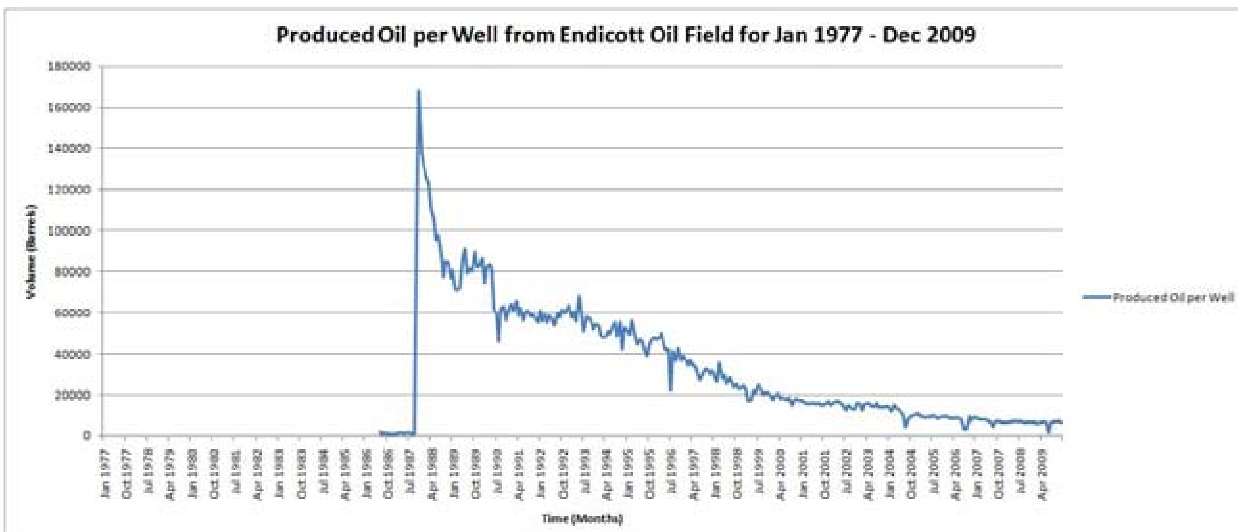


Figure G-12 Average volume of oil produced per well from the Endicott Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

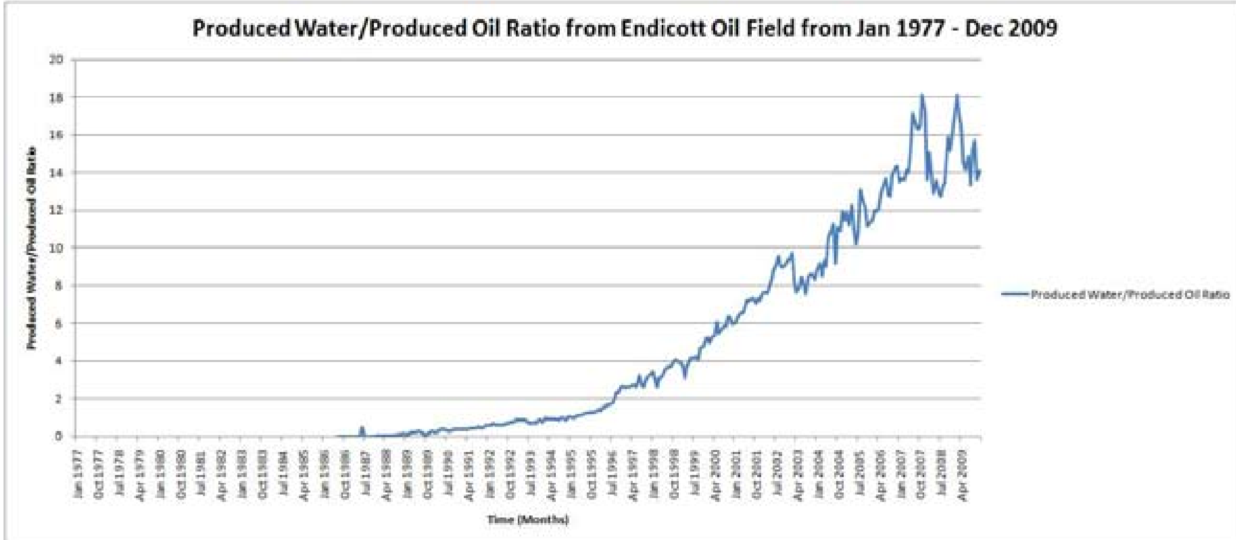


Figure G-13 Ratio of produced oil and produced water from the Endicott Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

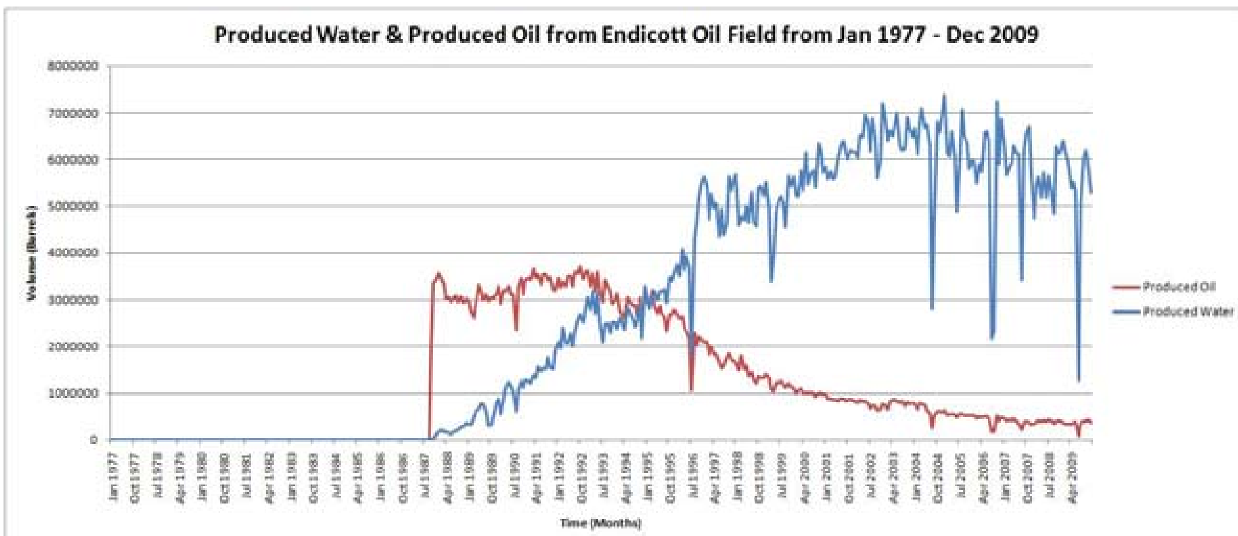


Figure G-14 Total monthly volume of produced oil and produced water from the Endicott Oil Field from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission. Produced Oil is shown in red, Produced Water is shown in blue.

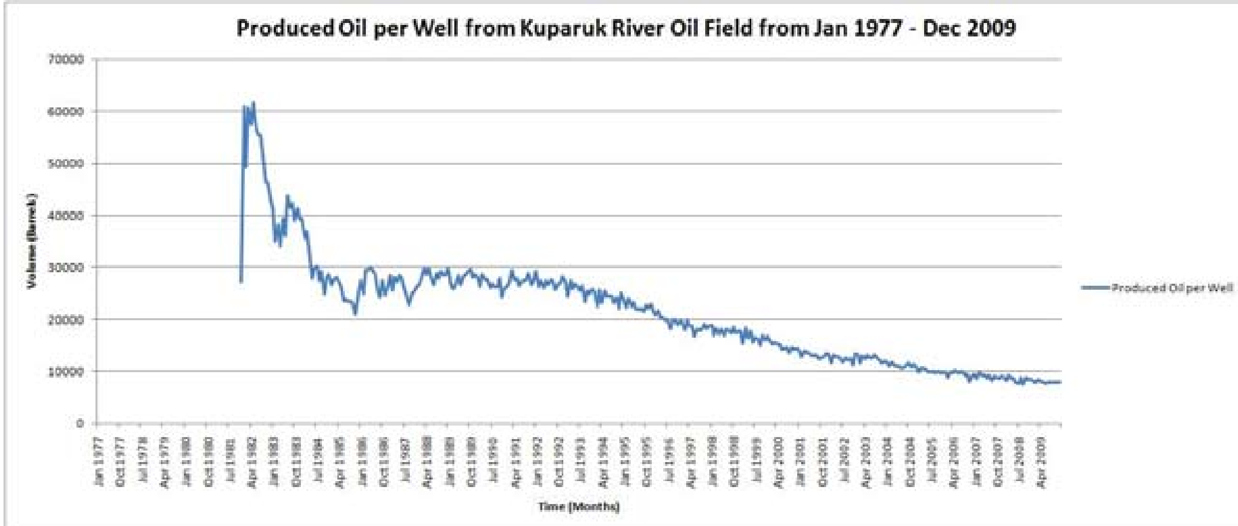


Figure G-15 Average volume of oil produced per well from the Kuparuk River Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

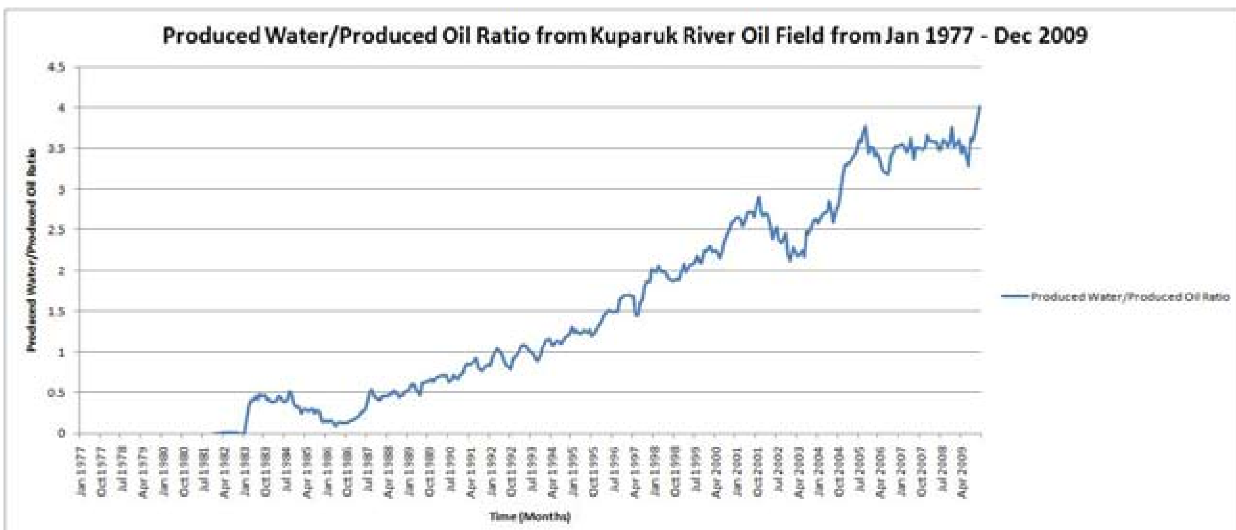


Figure G-16 Ratio of produced oil and produced water from the Kuparuk River Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

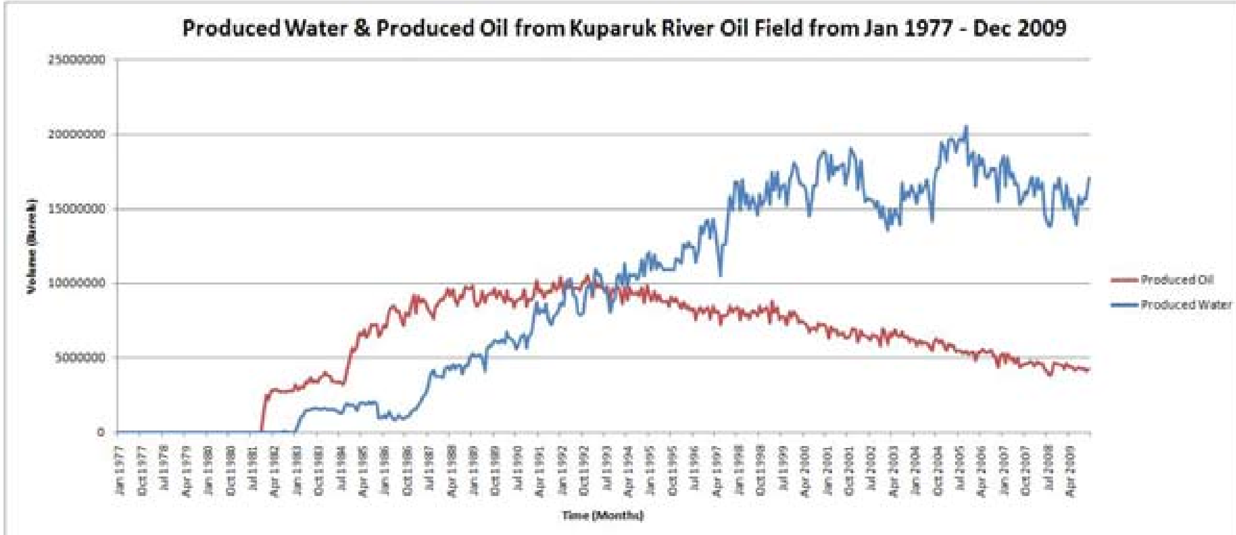


Figure G-17 Total monthly volume of produced oil and produced water from the Kuparuk River Oil Field from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission. Produced Oil is shown in red, Produced Water is shown in blue.

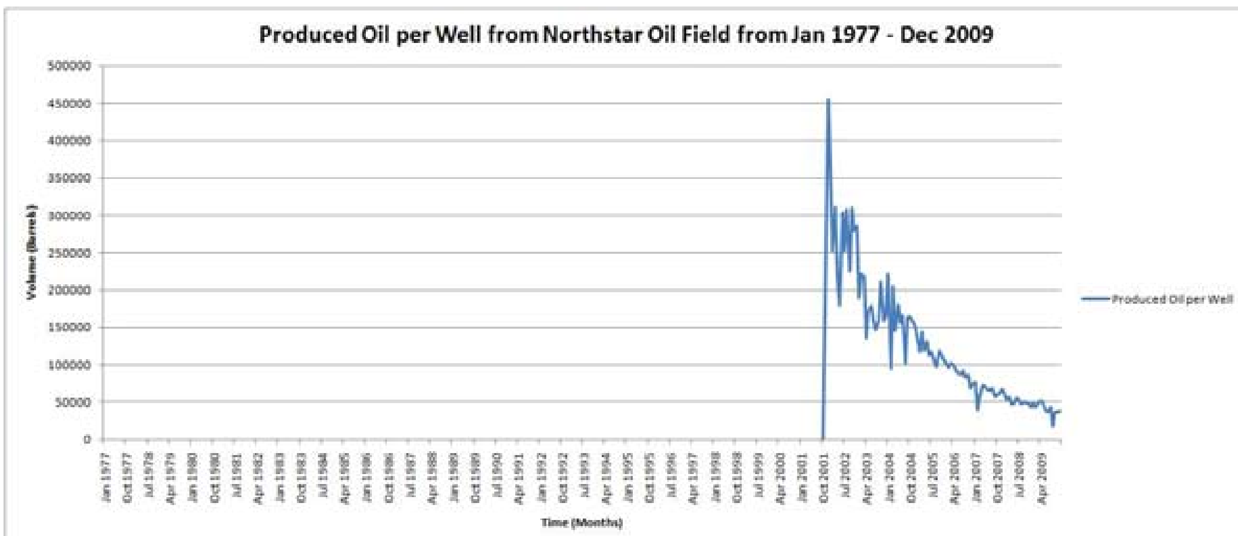


Figure G-18 Average volume of oil produced per well from the Northstar Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

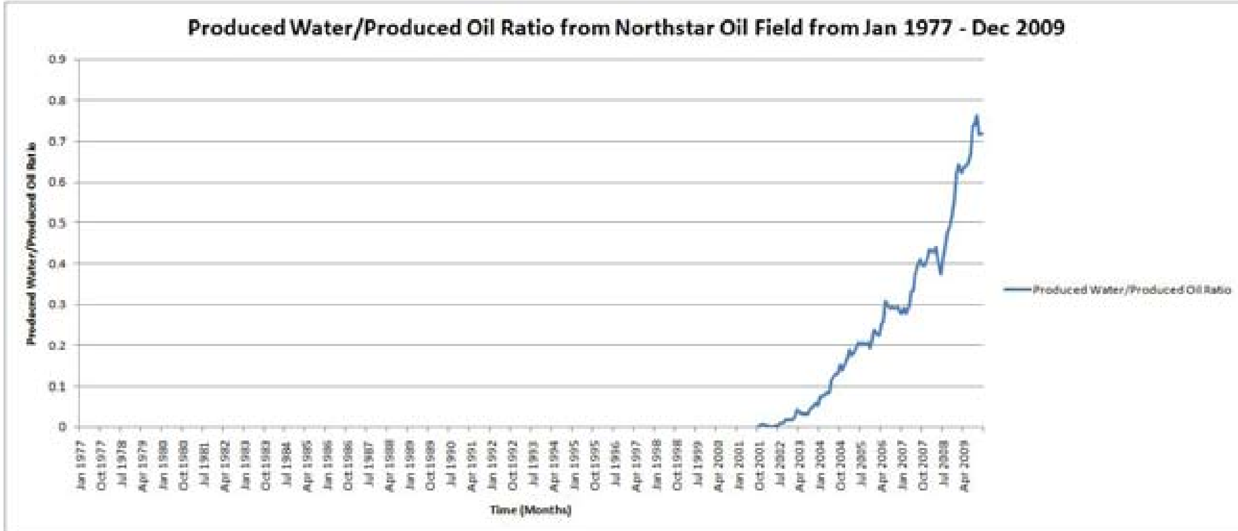


Figure G-19 Ratio of produced oil and produced water from the Northstar Oil Field from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

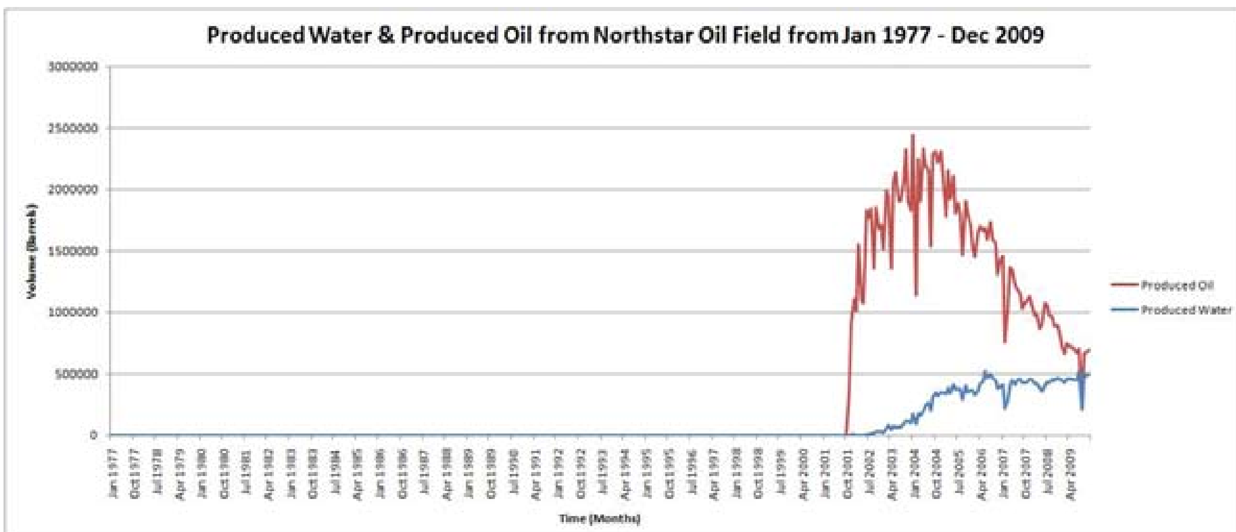


Figure G-20 Total monthly volume of produced oil and produced water from the Northstar Oil Field from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission. Produced Oil is shown in red, Produced Water is shown in blue.

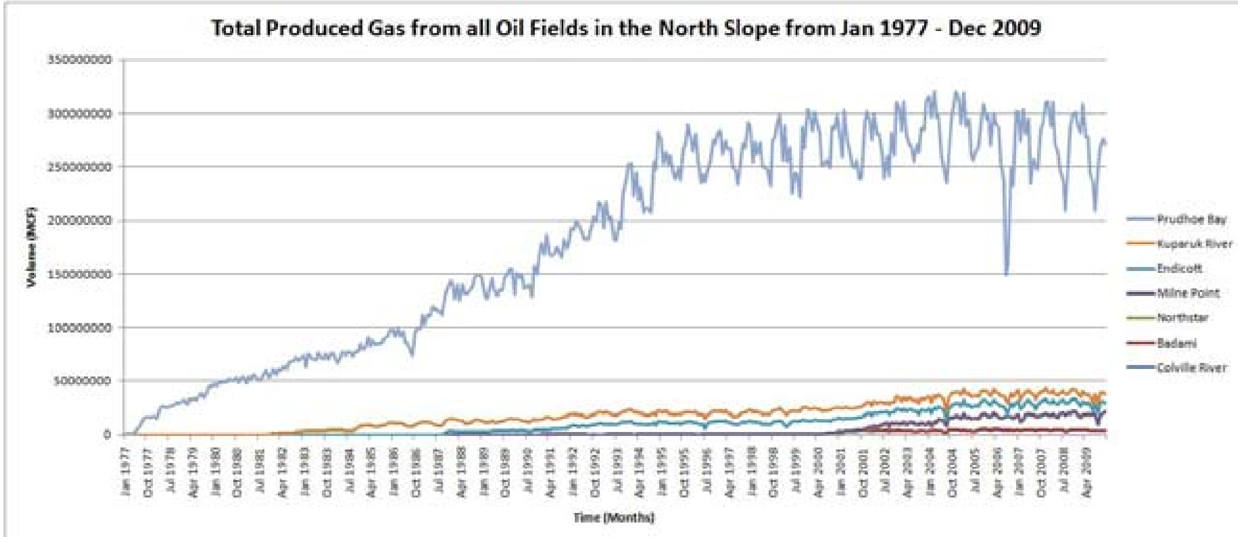


Figure G-21 Total combined monthly volume of produced gas from all oil fields in the North Slope from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission.

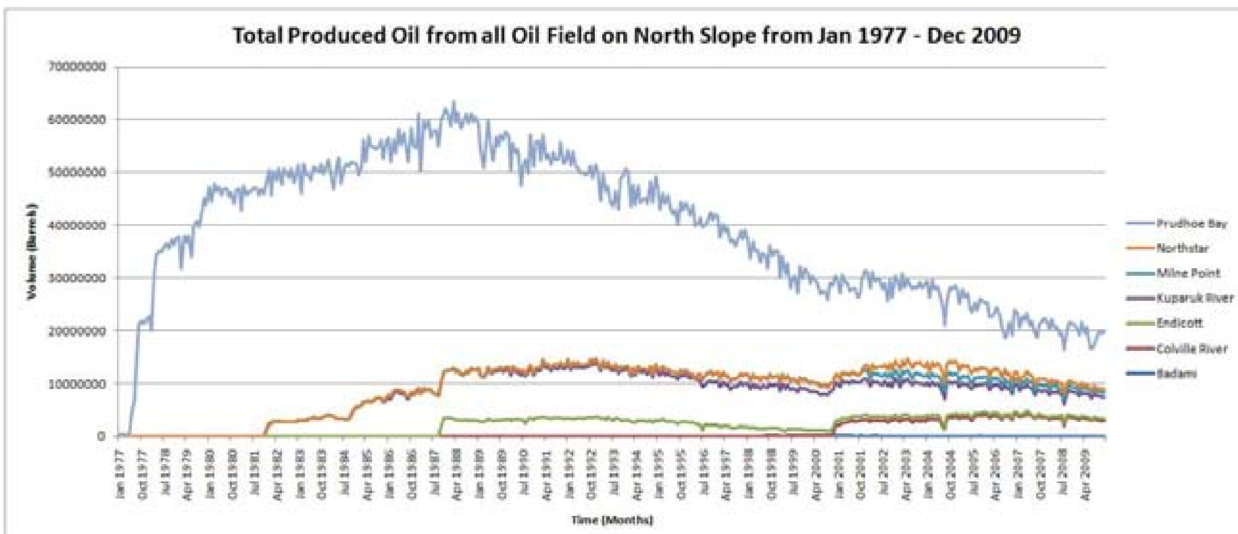


Figure G-22 Total combined monthly volume of produced oil from all oil fields in the North Slope from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission.

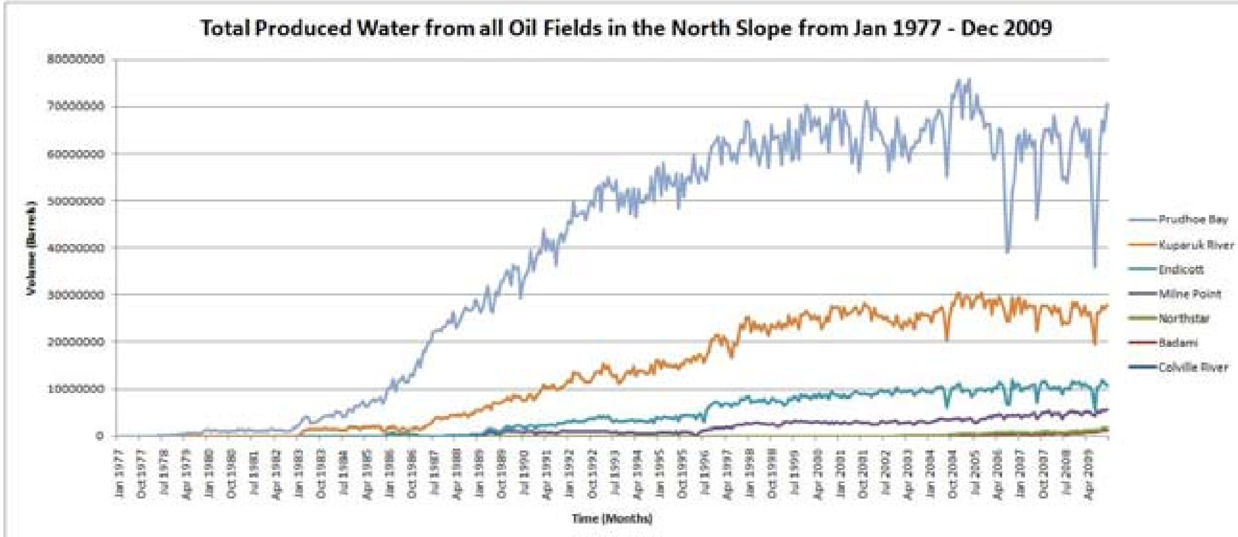


Figure G-23 Total combined monthly volume of produced water from all oil fields in the North Slope from January 1977 through December 2009 reported by the Alaska Oil and Gas Conservation Commission.

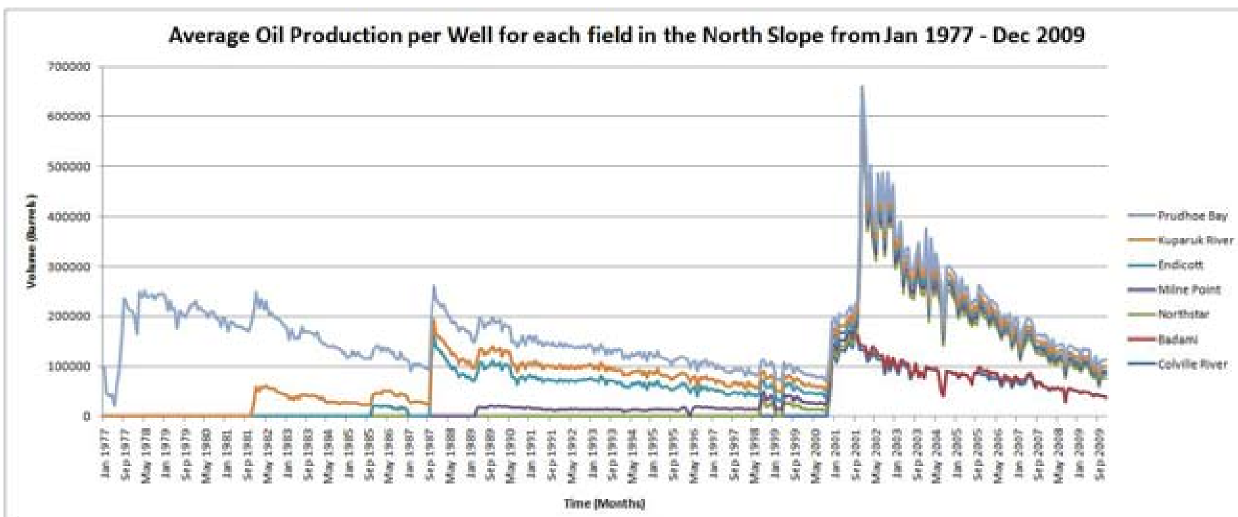


Figure G-24 Average combined monthly volume of produced oil per well from all oil fields in the North Slope from January 1977 through December 2009. Results were calculated from data reported by the Alaska Oil and Gas Conservation Commission.

APPENDIX H

H.1 Introduction

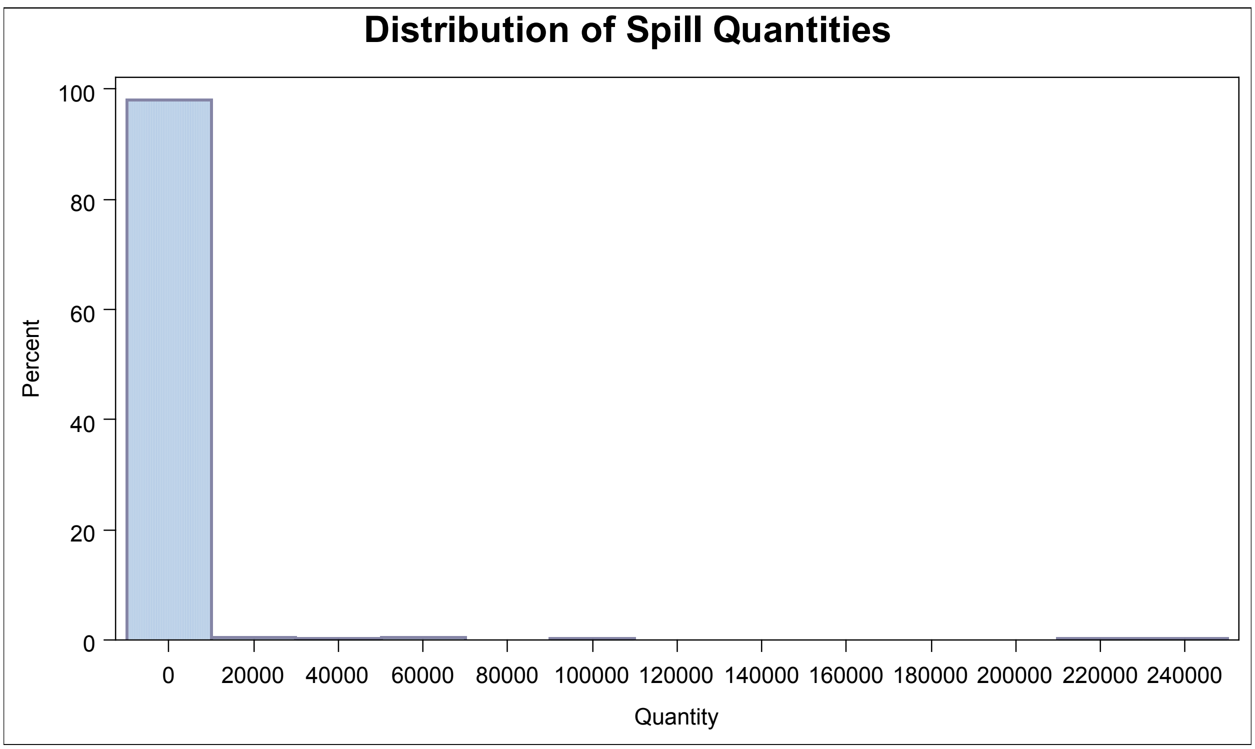
The first step in any statistical analysis is an exploratory data analysis. For this study it is important to begin with an examination of the distribution of the variable 'quantity of oil spills'.

Summary Statistics for the variable Quantity Spilled

Min	Max	Mean	Std Dev
0	241,038	1915.75	14746.63

Note a standard deviation that is extremely large relative to the mean.

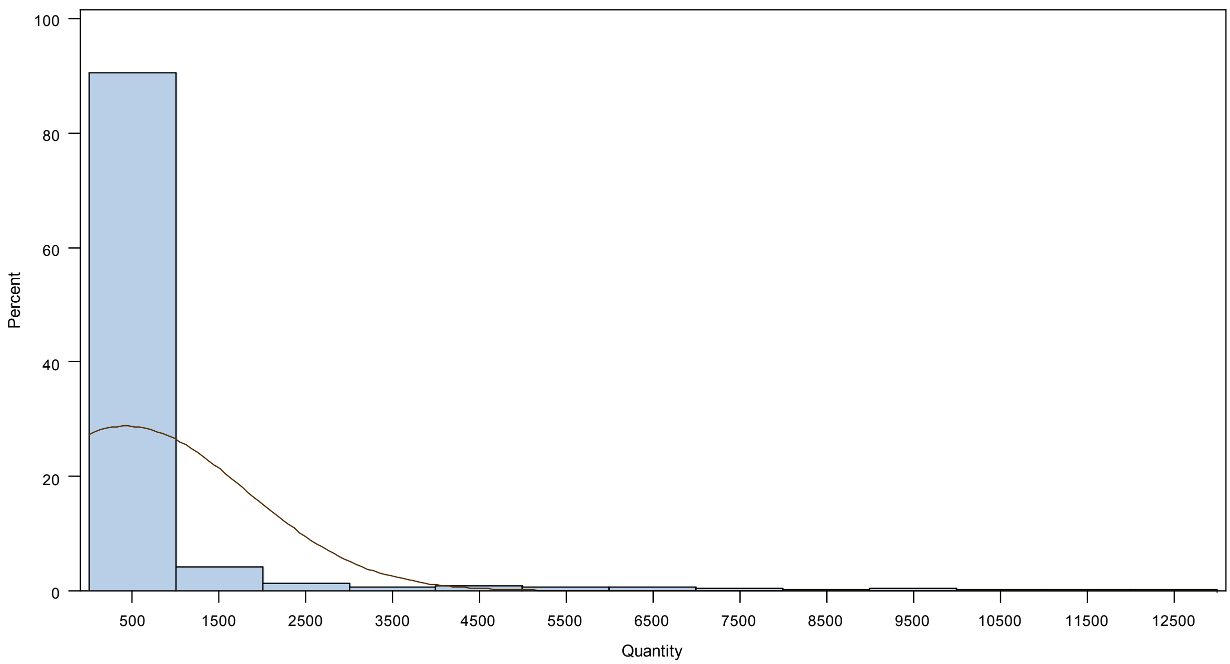
Consider a histogram of the data.



The conclusion is that the variable 'quantity spilled' is highly non-normal.

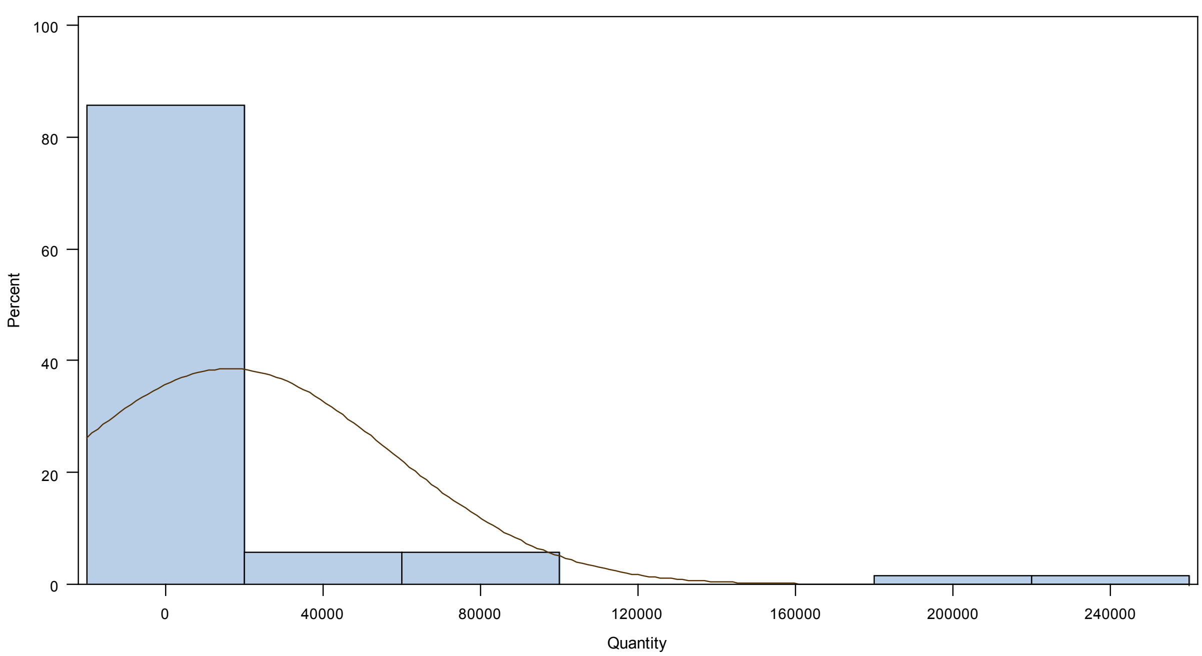
Consider two bins of data, one for spills less than 20,000 gallons and one for spills greater than 20,000 gallons. There are 10 spills (1.56% of total) of quantity greater than 20,000 gallons and 630 spills (98.44%) of quantity less than or equal to 20,000 gallons. Additionally, consider that the median for the distribution, another common measure of central tendency is 25 gallons.

Distribution of Spills with Quantity less than or equal to 20,000 Gal

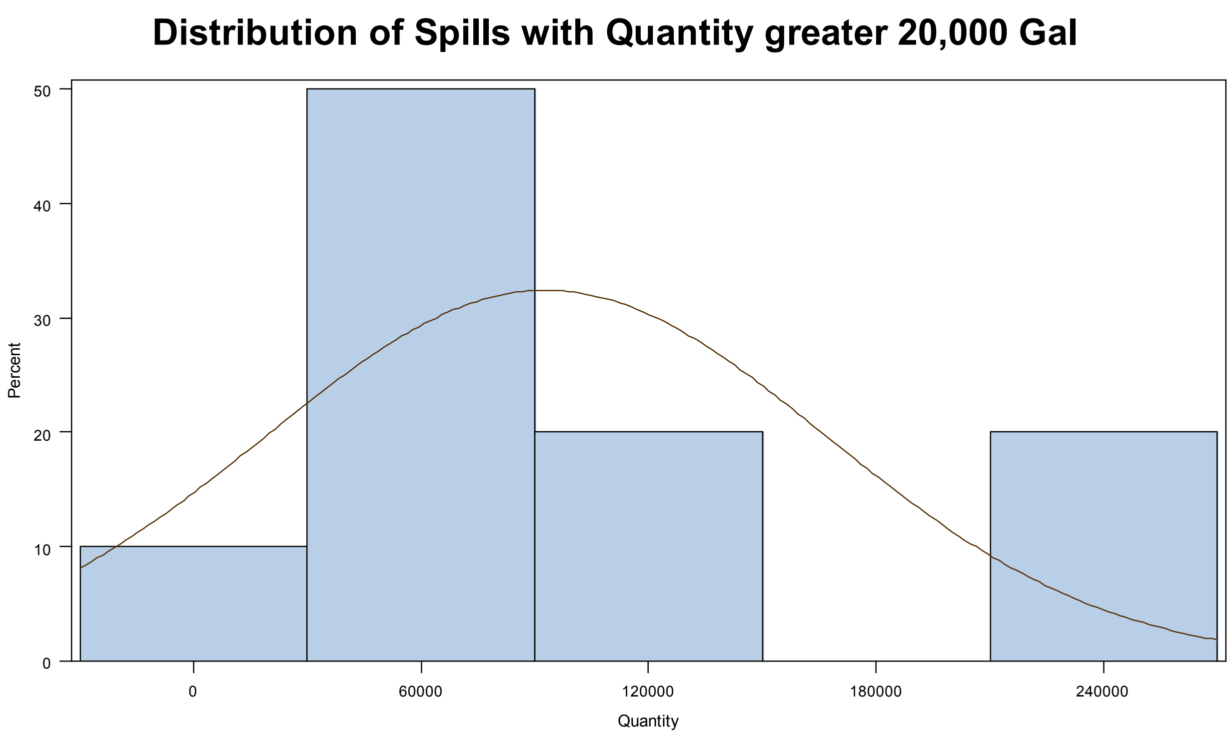


Consider only the spills where the quantity exceeded 1,000 gallons.

Distribution of Spills with Quantities Greater Than 1,000 Gal



Even the smaller spills of less than 20,000 gallons are not normally distributed. This indicates that the often used approach of discarding the extreme outliers is also not appropriate.



Of the large spills, only four have a volume greater than 90,000 gallons. The conclusion is that these large spills are quite rare. Two spills, both in Prudhoe Bay in 2006, have volume greater than 200,000 gallons. For the remainder of this report, these two will be referred to as the extreme outliers in the data set.

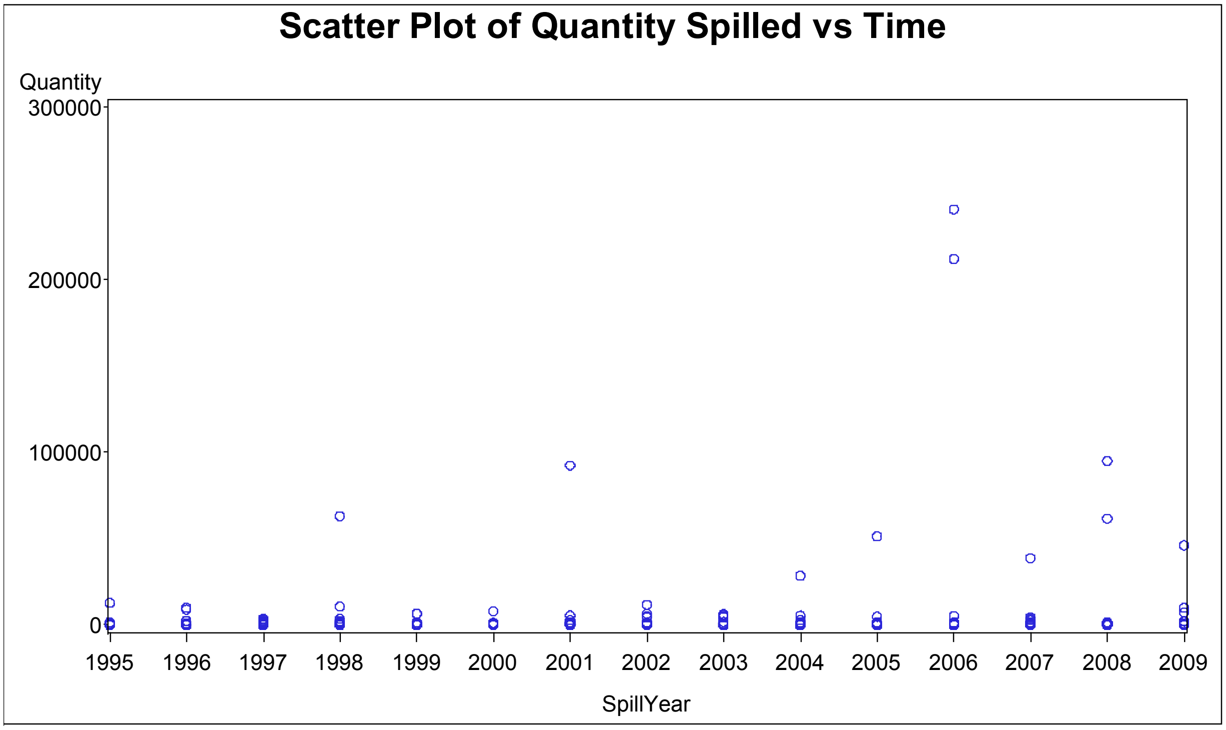
The consequences of the high non-normality in the data set are that many of the standard statistical techniques commonly employed are not valid. For instance, mean values, when influenced by extreme outliers, are not a good representation of central tendency for a variable. Furthermore, ordinary least squares regression has an underlying assumption of normally distributed data, and when this assumption is violated coefficient determination is not optimal and conclusions may be invalid. Finally, traditional error statistics reported as the mean plus or minus some factor of the standard error (1.96 for a 95% confidence interval) will have very little meaning as they will be based on both an inappropriate measure of central tendency and a greatly overstated estimate of standard error.

Consideration of the non-normality present in the spill data set will be crucial in the subsequent analysis of the data.

H.2 Analysis of Combined Loss-of-Integrity Spill Data

Analysis of the spill data begins with an examination of the aggregate data before breaking it into subcategories.

Consider a scatter plot of quantity spilled vs. year.



As expected, most of the points are clustered at the bottom of the graph. The two most extreme outliers occurred in the year 2006. Of the ten significant outliers, 80% of them occurred in the years 2004 to 2009. This suggests a trend of increasing spill quantity over time. Realizing that the data violates the key assumption of normality, the results of a linear regression are statistically not valid, never-the-less the results are presented below:

Linear Regression of spill quantity vs year

The GLM Procedure

Dependent Variable: Quantity Quantity

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	717571392.25	717571392.25	3.42	0.0649
Error	638	133854118305	209802693.27		
Corrected Total	639	134571689697			

R-Square	Coeff Var	Root MSE	Quantity Mean
0.005332	772.0012	14484.57	1876.236

Source	DF	Type I SS	Mean Square	F Value	Pr > F
SpillYear	1	717571392.3	717571392.3	3.42	0.0649

Source	DF	Type III SS	Mean Square	F Value	Pr > F
SpillYear	1	717571392.3	717571392.3	3.42	0.0649

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	-502963.7467	272978.0143	-1.84	0.0659
SpillYear	252.1487	136.3420	1.85	0.0649

At an alpha of 0.05, the hypothesis that quantity spilled is independent of year would not be rejected. At an alpha of 0.1 the hypothesis would be rejected. In essence this rough test indicates that there is some slight evidence of an increase in spill quantity over time, and, it is believed that even this slight upward trend is really the result of the two extreme outliers that occurred in 2006 exerting undue influence on the computation of the regression coefficients. This is supported by the fact that these two points had large values for the Cook's d statistic. Furthermore, with an extremely low R^2 value of 0.005, the overall conclusion is that time explains almost none of the total variability observed in quantity spilled.

Output of test with extreme outliers removed:

Linear Regression of spill quantity vs year

Two extreme outliers removed

The GLM Procedure

Dependent Variable: Quantity Quantity

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	109531984	109531984	2.13	0.1448
Error	636	32689100562	51397957		
Corrected Total	637	32798632547			

R-Square	Coeff Var	Root MSE	Quantity Mean
0.003340	611.9017	7169.237	1171.632

Source	DF	Type I SS	Mean Square	F Value	Pr > F
SpillYear	1	109531984.2	109531984.2	2.13	0.1448

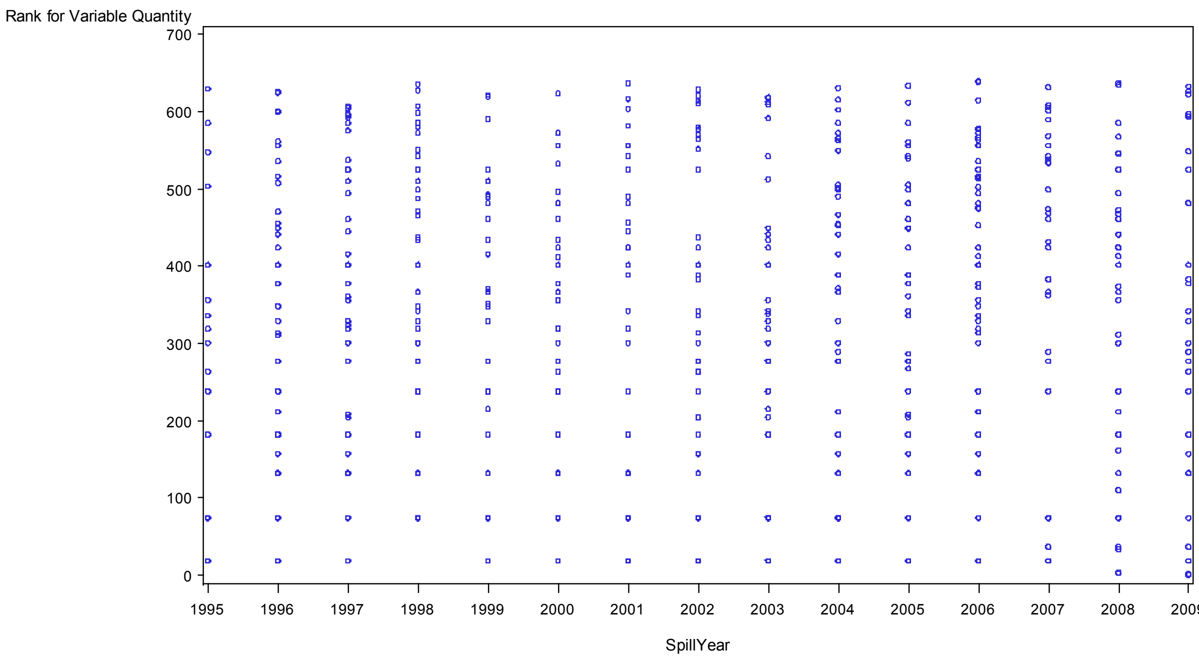
Source	DF	Type III SS	Mean Square	F Value	Pr > F
SpillYear	1	109531984.2	109531984.2	2.13	0.1448

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	-196325.8169	135289.7507	-1.45	0.1472
SpillYear	98.6432	67.5724	1.46	0.1448

When the two extreme outliers (large spills in 2006), the p-value for the regression becomes 0.1448, revealing that there is not significant evidence to reject the hypothesis that the mean quantity spilled is actually independent of year.

Because of the non-normality of the data, and the fact that it makes OLS regression essentially invalid, a non-parametric ranked test was also conducted. The 640 spills were all ranked in size based upon the volume of the spill. A scatter plot of the ranks vs. year is shown below:

Scatter Plot of Ranked Spills vs Time



Regression output:

Nonparametric regression of ranked spill quantity data

The GLM Procedure

Dependent Variable: Q_rank Rank for Variable Quantity

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	17023.06	17023.06	0.50	0.4803
Error	638	21776255.44	34132.06		
Corrected Total	639	21793278.50			

R-Square	Coeff Var	Root MSE	Q_rank Mean
0.000781	57.64388	184.7486	320.5000

Source	DF	Type I SS	Mean Square	F Value	Pr > F
SpillYear	1	17023.05872	17023.05872	0.50	0.4803

Source	DF	Type III SS	Mean Square	F Value	Pr > F
SpillYear	1	17023.05872	17023.05872	0.50	0.4803

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	-2138.395001	3481.796645	-0.61	0.5393
SpillYear	1.228126	1.739024	0.71	0.4803

The more valid non-parametric test supports the conclusion that spill quantity is independent of time.

The question also arises as to whether the number of spills is time dependent. In order to perform this analysis, the number of spills per year had to first be tabulated. Additionally, since the database only included data for the last six months of 1995, all of the data from that year was excluded from the analysis.

Summary of number of spills and quantity spilled by year

Year	Count	Total Spilled
1996	51	26,843.00
1997	46	18,098.00
1998	52	87,506.00
1999	35	16,642.00
2000	41	12,577.00
2001	40	105,071.00
2002	40	33,158.00
2003	50	24,452.00
2004	45	42,493.00
2005	44	62,179.00
2006	55	469,311.00
2007	35	54,583.00
2008	47	162,522.23
2009	38	70,412.06

Regression output:

Linear regression of number of spills vs year

The GLM Procedure

Dependent Variable: Count Count

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	18.8582418	18.8582418	0.45	0.5153
Error	12	503.4989011	41.9582418		
Corrected Total	13	522.3571429			

R-Square	Coeff Var	Root MSE	Count Mean
0.036102	14.65028	6.477518	44.21429

Source	DF	Type I SS	Mean Square	F Value	Pr > F
SpillYear	1	18.85824176	18.85824176	0.45	0.5153

Source	DF	Type III SS	Mean Square	F Value	Pr > F
SpillYear	1	18.85824176	18.85824176	0.45	0.5153

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	620.7582418	859.9859276	0.72	0.4842
SpillYear	-0.2879121	0.4294553	-0.67	0.5153

With a p-value of 0.5153 there is not sufficient evidence to reject the null hypothesis that, when considering all spills recorded, the number of spills is independent of year.

Next consider spills by size.

Tabulate the number of spills in each size category where: 1) < 10 2) 10 – 100 3) 100 – 1,000 4) 1,000 – 10,000 5) 10,000 – 100,000 6) > 100,000

Tabulate Numbers of each spill size

Category	Number in Category
1	216
2	201
3	153
4	57
5	11
6	2

To explore which factors might effect spill size category a Chi-square test was run on the contingency table shown below. The number of samples in the last two spill size categories was very small, so to overcome the limitations that this places on the analysis, the data was collapsed from 6 to 4 categories. The fourth category contained the 70 spills with volume greater than 1,000 gallons.

Investigate independence of spill size and oil field

The FREQ Procedure

Table of Oil_Field by size

Oil_Field(Oil Field) / size Frequency Percent Row Pct Col Pct	< 10	10 - 100	100 - 1,000	> 1,000	Total
Badami	1 0.16 25.00 0.46	2 0.31 50.00 1.00	1 0.16 25.00 0.65	0 0.00 0.00 0.00	4 0.63
Colville River, Alpine	2 0.31 40.00 0.93	1 0.16 20.00 0.50	1 0.16 20.00 0.65	1 0.16 20.00 1.43	5 0.78
Endicott	3 0.47 30.00 1.39	2 0.31 20.00 1.00	3 0.47 30.00 1.96	2 0.31 20.00 2.86	10 1.56
Kuparuk River	33 5.16 23.91 15.28	40 6.25 28.99 19.90	44 6.88 31.88 28.76	21 3.28 15.22 30.00	138 21.56

```
Milne Point     ,    11 ,    14 ,     8 ,     8 ,    41
                ,  1.72 ,  2.19 ,  1.25 ,  1.25 ,  6.41
                , 26.83 , 34.15 , 19.51 , 19.51 ,
                ,  5.09 ,  6.97 ,  5.23 , 11.43 ,
ƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆ
North Star      ,     2 ,     2 ,     0 ,     0 ,     4
                ,  0.31 ,  0.31 ,  0.00 ,  0.00 ,  0.63
                , 50.00 , 50.00 ,  0.00 ,  0.00 ,
                ,  0.93 ,  1.00 ,  0.00 ,  0.00 ,
ƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆ
Prudhoe Bay     ,   164 ,   140 ,    96 ,    38 ,   438
                , 25.63 , 21.88 , 15.00 ,  5.94 , 68.44
                , 37.44 , 31.96 , 21.92 ,  8.68 ,
                , 75.93 , 69.65 , 62.75 , 54.29 ,
ƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆƒƒƒƒƒƒƒƒˆ
Total                216      201      153       70      640
                   33.75    31.41    23.91    10.94   100.00

        Statistics for Table of Oil_Field by size

   Statistic                     DF       Value      Prob
   ƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒ
   Chi-Square                    18     23.7046    0.1649
   Likelihood Ratio Chi-Square   18     24.7359    0.1324
   Mantel-Haenszel Chi-Square     1     13.6512    0.0002
   Phi Coefficient                       0.1925
   Contingency Coefficient               0.1890
   Cramer's V                            0.1111

    WARNING: 61% of the cells have expected counts less
             than 5. Chi-Square may not be a valid test.

                     Sample Size = 640
```

Given the small counts in some of the cells, the Likelihood Ratio Chi-Square test is more appropriate than the Pearson Chi-Square statistic listed first. However, both yield the same conclusion. There is not sufficient evidence to reject the null hypothesis that size of an oil spill is independent of the oilfield at which it occurred.

Next the data were reviewed to determine if large spills, defined as quantity greater than 1,000 gallons have experienced a change in frequency with time. Despite the weaknesses with the approach enumerated above, a linear regression was run.

Output:

```
                 Linear Regression of spill quantity vs year

                            The GLM Procedure

Dependent Variable: Quantity   Quantity

                                   Sum of
     Source                DF        Squares    Mean Square   F Value   Pr > F

     Model                  1     6398254670     6398254670      3.90   0.0524

     Error                 68   111653107305   1641957460.4

     Corrected Total       69   118051361975


             R-Square     Coeff Var      Root MSE    Quantity Mean

             0.054199      247.5740      40521.07         16367.26
```

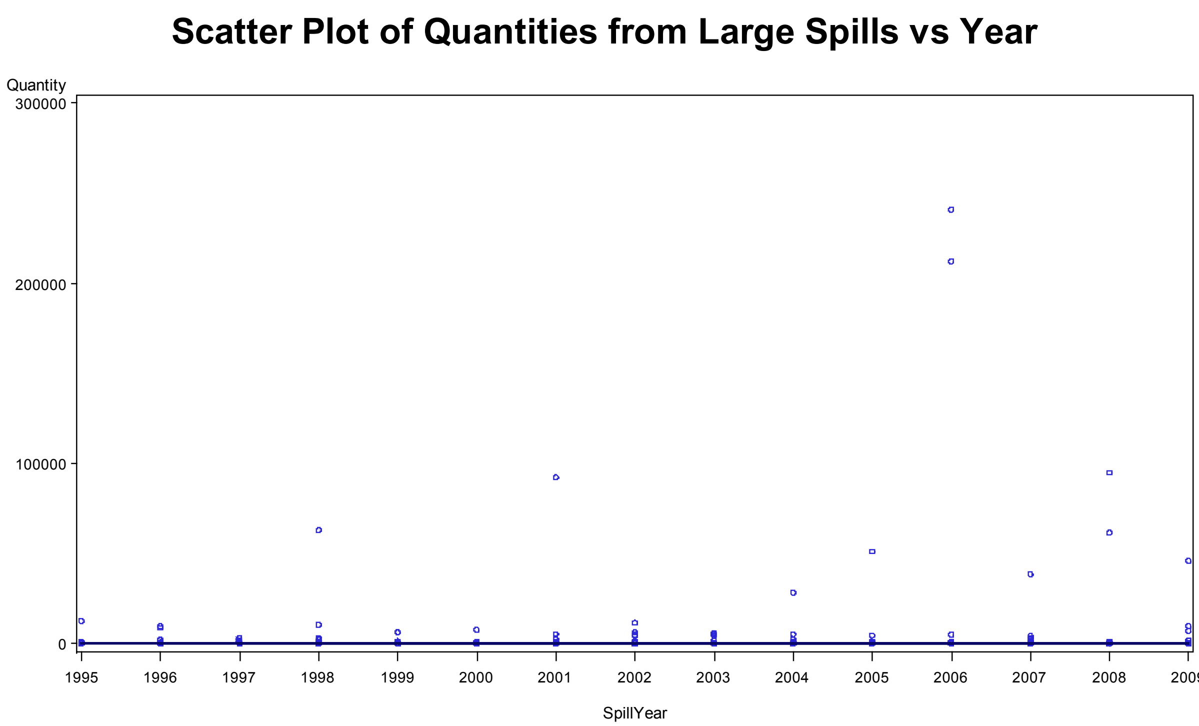
Source	DF	Type I SS	Mean Square	F Value	Pr > F
SpillYear	1	6398254670	6398254670	3.90	0.0524

Source	DF	Type III SS	Mean Square	F Value	Pr > F
SpillYear	1	6398254670	6398254670	3.90	0.0524

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	-4492008.311	2283869.336	-1.97	0.0533
SpillYear	2251.791	1140.718	1.97	0.0524

The conclusion, with a p-value of 0.0524, is that, for a subset of the data focusing on the 70 largest spills, there is some slight evidence suggesting an increase in quantity spilled vs. time. However, the non-normality problem coupled with the extreme outliers in 2006 makes this conclusion for the large spills just as suspect as were the results from the linear regression done on the entire data set.

A plot of the data with the regression line superimposed is shown below:



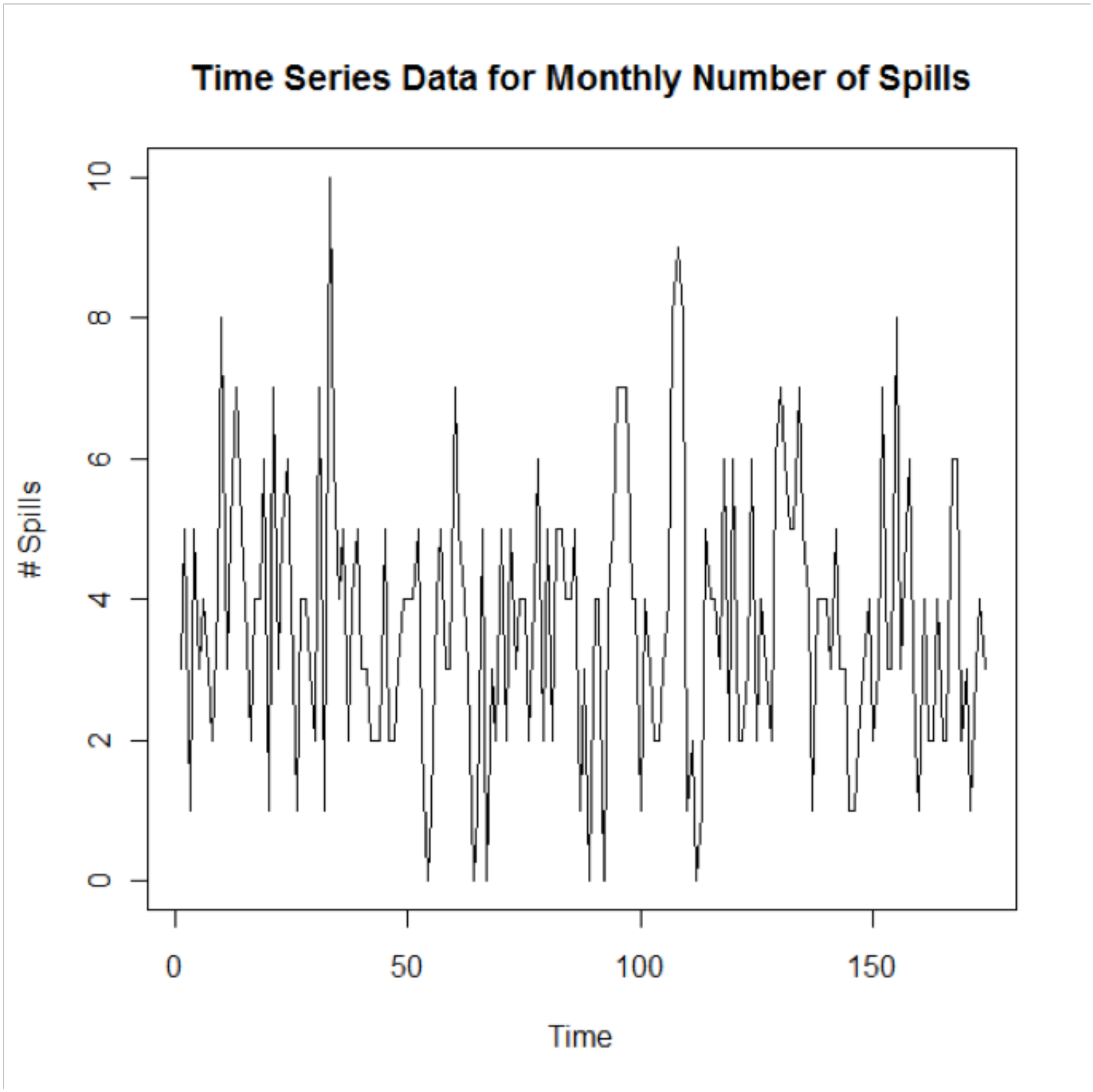
Note that the best fit line continues to look essentially flat, lying nearly on the x-axis of the graph.

The number of large spills each year should also be considered. However, it is quite clear from the following table that the number of large spills is not increasing over time.

Summary of Large Spills by Year

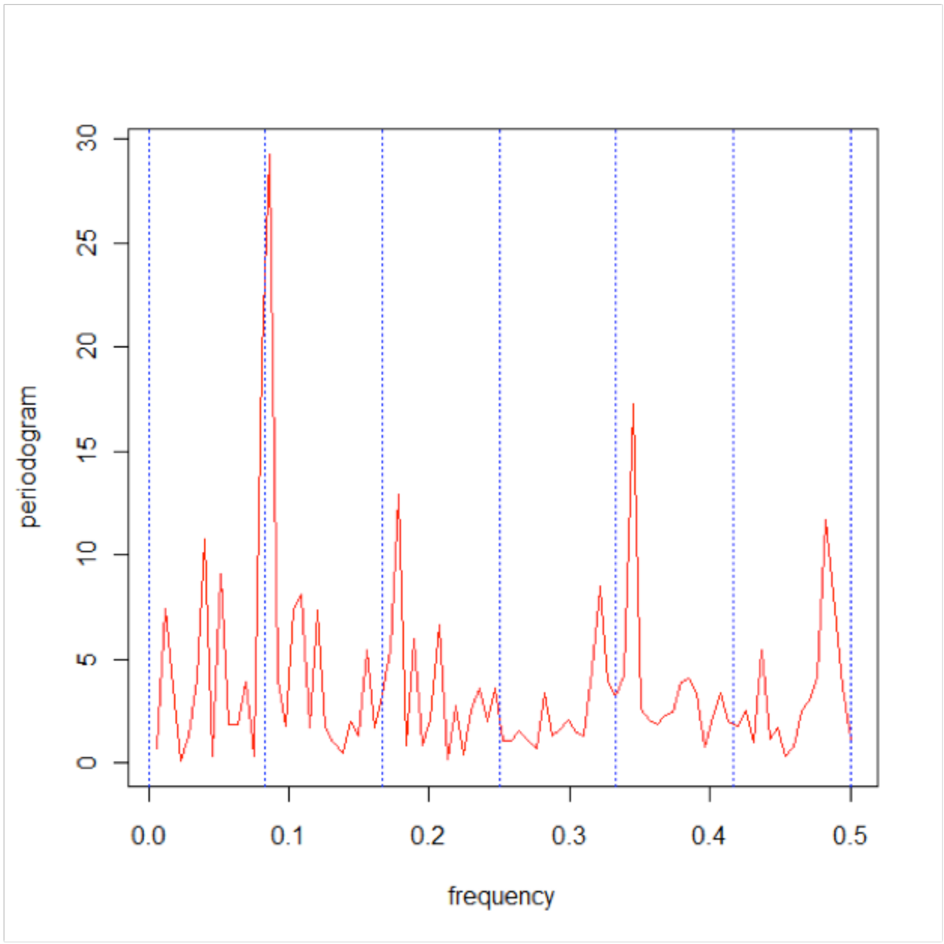
Year	Count	Total Spilled
1996	4	22,933.00
1997	7	14,364.00
1998	8	83,680.00
1999	3	14,034.00
2000	3	9,754.00
2001	4	101,604.00
2002	6	29,629.00
2003	5	22,592.00
2004	5	38,380.00
2005	3	57,058.00
2006	6	461,502.00
2007	5	49,935.00
2008	3	157,806.00
2009	6	68,577.00

Finally, it is important to examine the data for cyclical behavior. To do so, it was first summarized by month so as to create an evenly spaced time series. Below is a plot of the number of spills by month for all months from the second half of 1995 through 2009.



Next, look at a periodogram of the monthly data:

The vertical blue lines in the plot below are plotted at frequencies of n/12 for n = {0, 1, 2, 3, 4, 5, 6}. Interestingly, the largest peak falls at a frequency of 1/12. The occurrence of this peak strongly indicates that there is annual cyclical behavior in the time series.



With evidence of cyclical behavior exhibited in the periodogram, the next question is which months have the highest number of spills? The table below lists average number of spills by month. Evidently, the greatest number of spills occur in June.

Month	Mean Count
1	3.31
2	3.15
3	4.21
4	4.57
5	4.57
6	5.29
7	4.13
8	3.73
9	3.00
10	3.23
11	2.86
12	3.57

Conclusions pertaining to time dependence of oil spills:

1. There is no trend in the number of spills observed versus time, either for the complete data set or for a subset focusing exclusively on spills greater than 1,000 gallons.
2. There is some slight evidence that the volume of oil spilled has increased with time. However, non-normality of the data, due largely to the existence of a few extreme outliers, clouds the issue.
3. Non-parametric tests focusing on ranked spill sizes as opposed to absolute quantity of spill size shows no increase in spill size over time.
4. An examination of the data for cyclical behavior found strong evidence of periodicity in the data. The maximum number of spills apparently occur in June.

H.3 Analysis of Spill Data by Primary Cause of Failure

Investigations of spill causes often cite multiple causes. An expert panel descided that some of these causes were too vague to provide much usable information. So, this study focused on 501 cases for which the identifiable primary causes were one or more of those listed in the following table. Note: This analysis DOES NOT include the December 19, 2006 spill, the largest in the database, because the primary cause for this spill was listed as simply 'Material Failure of Pipe or Weld'.

Contributing Primary Causes (455 Cases considered)	Number of Cases Cited	Detail	Percent of Cases
Corrosion	92		18.36%
External Corrosion		17	
External Corrosion at or near weld joints		8	
Internal Corrosion		54	
Unspecified Corrosion		13	
Erosion	20		3.99%
External Erosion		2	
Internal Erosion		17	
Unspecified Erosion		1	
Thermal Expansion	39		7.78%
Construction, Installation or Fabrication Related	11		2.20%
Original Manufacturing Related	0		0.00%
Vibration (Wind-induced Slugging)	5		1.00%
Overpressure	24		4.79%
Valve/Seal Failure	249		49.70%
Operator Error	84		16.77%
Third Party Action	1		0.20%

Note: Because some cases cited multiple primary causes, the table above should be interpreted that 'Corrosion' was cited as at least one of the primary causes in 18.36% of the 501 cases. The total for the percent column sums to 104.79% because of the multiple cause issue.

It is evident the large majority of spills is caused by valve or seal failure.

For the next part of the analysis, each spill case was limited to having one primary cause. This was arbitrarily set at the first cause listed in the column entitled 'Primary Causes'. The goal was to avoid double counting cases so that comparisons could be made with causes and other variables.

Consider whether primary cause and regulatory category are independent:

Test for independence of regulatory category and cause

Table of Regulatory_Category by Cause

Regulatory_Category(Regulatory Category) Cause(Cause)

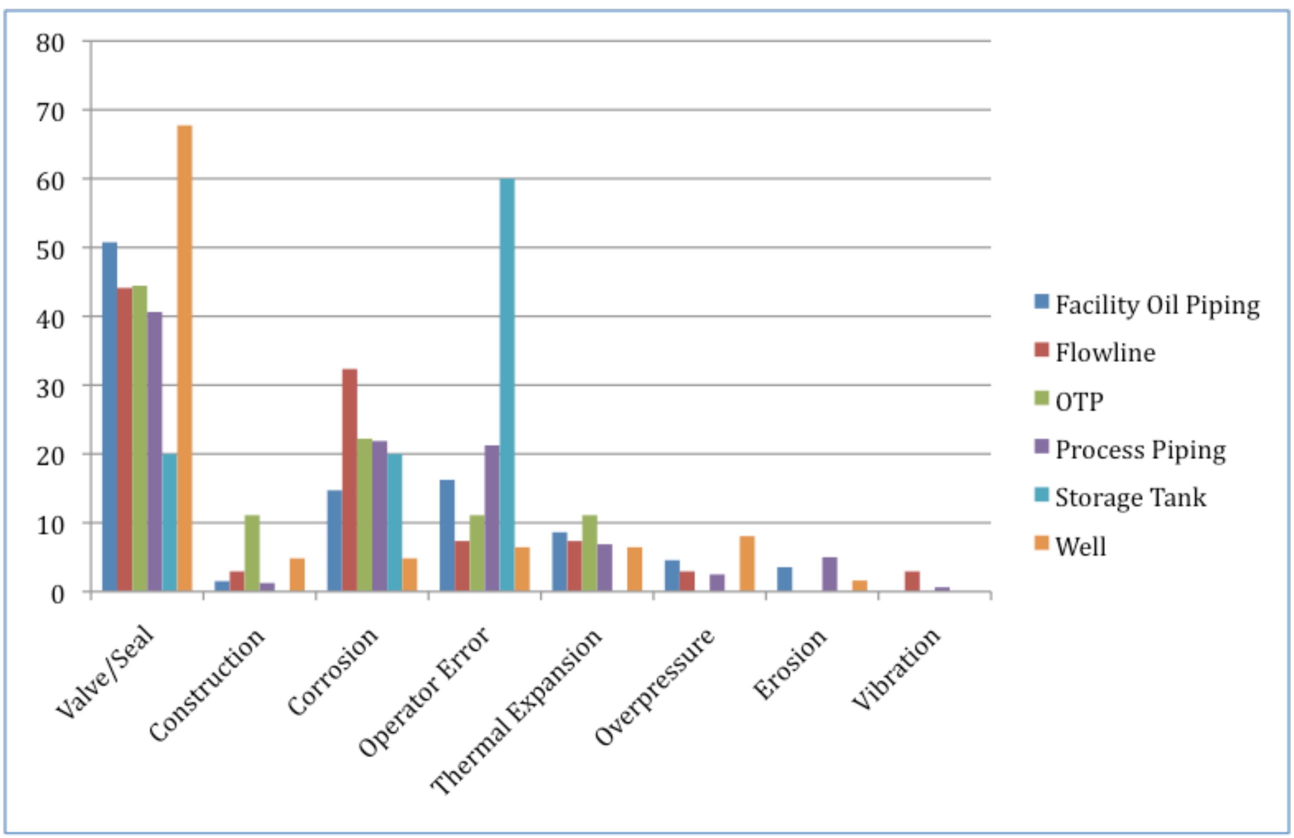
Regulatory_Category	Frequency / Percent / Row Pct / Col Pct	Valve/Seal	Construction	Corrosion	Operator Error	Thermal Expansion	Over Pressure	Errosion	Vibration	Total
Facility Oil Piping	Frequency	100	3	29	32	17	9	7	0	197
	Percent	19.96	0.60	5.79	6.39	3.39	1.80	1.40	0.00	39.32
	Row Pct	50.76	1.52	14.72	16.24	8.63	4.57	3.55	0.00	
	Col Pct	41.32	27.27	31.52	40.51	44.74	45.00	43.75	0.00	
Flowline	Frequency	30	2	22	5	5	2	0	2	68
	Percent	5.99	0.40	4.39	1.00	1.00	0.40	0.00	0.40	13.57
	Row Pct	44.12	2.94	32.35	7.35	7.35	2.94	0.00	2.94	
	Col Pct	12.40	18.18	23.91	6.33	13.16	10.00	0.00	66.67	
Oil Transmission Pipeline	Frequency	4	1	2	1	1	0	0	0	9
	Percent	0.80	0.20	0.40	0.20	0.20	0.00	0.00	0.00	1.80
	Row Pct	44.44	11.11	22.22	11.11	11.11	0.00	0.00	0.00	
	Col Pct	1.65	9.09	2.17	1.27	2.63	0.00	0.00	0.00	
Process Piping	Frequency	65	2	35	34	11	4	8	1	160
	Percent	12.97	0.40	6.99	6.79	2.20	0.80	1.60	0.20	31.94
	Row Pct	40.63	1.25	21.88	21.25	6.88	2.50	5.00	0.63	
	Col Pct	26.86	18.18	38.04	43.04	28.95	20.00	50.00	33.33	
Storage Tank	Frequency	1	0	1	3	0	0	0	0	5
	Percent	0.20	0.00	0.20	0.60	0.00	0.00	0.00	0.00	1.00
	Row Pct	20.00	0.00	20.00	60.00	0.00	0.00	0.00	0.00	
	Col Pct	0.41	0.00	1.09	3.80	0.00	0.00	0.00	0.00	
Well	Frequency	42	3	3	4	4	5	1	0	62
	Percent	8.38	0.60	0.60	0.80	0.80	1.00	0.20	0.00	12.38
	Row Pct	67.74	4.84	4.84	6.45	6.45	8.06	1.61	0.00	
	Col Pct	17.36	27.27	3.26	5.06	10.53	25.00	6.25	0.00	
Total		242	11	92	79	38	20	16	3	501
		48.30	2.20	18.36	15.77	7.58	3.99	3.19	0.60	100.00

```
Test for independence of regulatory category and cause

                The FREQ Procedure

 Statistics for Table of Regulatory_Category by Cause

Statistic                DF      Value      Prob
ƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒƒ
Chi-Square                   35    64.6873    0.0017
Likelihood Ratio Chi-Square   35    64.3020    0.0018
Mantel-Haenszel Chi-Square    1     0.3186    0.5725
Phi Coefficient                     0.3593
Contingency Coefficient             0.3382
Cramer's V                          0.1607

 WARNING: 60% of the cells have expected counts less
         than 5. Chi-Square may not be a valid test.

                Sample Size = 501
```

With p-value of 0.0018 for the Likelihood Ratio Chi-Square, the hypothesis that regulatory category and cause are independent must be rejected. Valve/seal failures generally account for the largest cause of spills in most regulatory categories. The three most notable instances where dependence is evident between cause and regulatory category are:

1. Valve/seal failures account for an unusually high percentage of well spills.
2. Operator error accounts for an unusually high percentage of storage tank spills.
3. Corrosion accounts for an unusually high percentage of flowline spills.

The following graph illustrates this.



Next, focus on the two largest oil fields and test to see whether cause and oil field are independent:

Test for independence oil field and cause

Table of Oil_Field by Cause

Oil_Field(Oil Field) Cause(Cause)

Frequency
Percent
Row Pct
Col Pct

Oil_Field	Statistic	Valve/Seal	Construction	Corrosion	Operator Error	Thermal Expansion	Over Pressure	Errosion	Vibration	Total
Kuparuk River	Frequency	47	2	30	17	10	0	3	0	109
	Percent	10.66	0.45	6.80	3.85	2.27	0.00	0.68	0.00	24.72
	Row Pct	43.12	1.83	27.52	15.60	9.17	0.00	2.75	0.00	
	Col Pct	22.07	33.33	34.09	23.94	33.33	0.00	25.00	0.00	
Prudhoe Bay	Frequency	166	4	58	54	20	18	9	3	332
	Percent	37.64	0.91	13.15	12.24	4.54	4.08	2.04	0.68	75.28
	Row Pct	50.00	1.20	17.47	16.27	6.02	5.42	2.71	0.90	
	Col Pct	77.93	66.67	65.91	76.06	66.67	100.00	75.00	100.00	
Total		213	6	88	71	30	18	12	3	441
		48.30	1.36	19.95	16.10	6.80	4.08	2.72	0.68	100.00

Statistics for Table of Oil_Field by Cause

Statistic	DF	Value	Prob
Chi-Square	7	13.3148	0.0648
Likelihood Ratio Chi-Square	7	17.9834	0.0120
Mantel-Haenszel Chi-Square	1	0.0089	0.9250
Phi Coefficient		0.1738	
Contingency Coefficient		0.1712	
Cramer's V		0.1738	

WARNING: 38% of the cells have expected counts less than 5. Chi-Square may not be a valid test.

Sample Size = 441

Because some contingency table cells have low expected counts, it is best to use the Likelihood Ratio Chi-Square statistic when considering independence. Based upon the p-value of 0.0120 for this test, the hypothesis that spill causes are independent of oil field should be rejected. The most significant difference appears to be that corrosion is a significantly bigger problem for Kuparak River than for Prudhoe Bay.

Finally, consider whether or not quantity spilled is independent of cause. Again, remember that the largest spill is not included in this analysis.

The spills were divided into 6 categories as follows:

```
1="Less than or equal to 1"
2="1 to 10"
3="10 to 100"
4="100 to 1,000"
5="1,000 to 10,000"
6="Greater than 10,000"
```

A Chi-square test was run to consider the null hypothesis that spill size was independent of cause:

Test independence of spill size and cause

The FREQ Procedure

Table of Size by Cause

Size	Frequency / Percent / Row Pct / Col Pct	Valve/Seal	Construction	Corrosion	Operator Error	Thermal Expansion	Over Pressure	Errosion	Vibration	Total
Less than or equal to 1	Frequency	14	1	5	1	1	0	0	0	22
	Percent	2.79	0.20	1.00	0.20	0.20	0.00	0.00	0.00	4.39
	Row Pct	63.64	4.55	22.73	4.55	4.55	0.00	0.00	0.00	
	Col Pct	5.79	9.09	5.43	1.27	2.63	0.00	0.00	0.00	
1 to 10	Frequency	96	4	12	31	14	10	1	0	168
	Percent	19.16	0.80	2.40	6.19	2.79	2.00	0.20	0.00	33.53
	Row Pct	57.14	2.38	7.14	18.45	8.33	5.95	0.60	0.00	
	Col Pct	39.67	36.36	13.04	39.24	36.84	50.00	6.25	0.00	
10 to 100	Frequency	63	2	23	26	10	6	6	1	137
	Percent	12.57	0.40	4.59	5.19	2.00	1.20	1.20	0.20	27.35
	Row Pct	45.99	1.46	16.79	18.98	7.30	4.38	4.38	0.73	
	Col Pct	26.03	18.18	25.00	32.91	26.32	30.00	37.50	33.33	
100 to 1,000	Frequency	51	4	29	16	8	4	6	1	119
	Percent	10.18	0.80	5.79	3.19	1.60	0.80	1.20	0.20	23.75
	Row Pct	42.86	3.36	24.37	13.45	6.72	3.36	5.04	0.84	
	Col Pct	21.07	36.36	31.52	20.25	21.05	20.00	37.50	33.33	
1,000 to 10,000	Frequency	16	0	16	5	4	0	3	1	45
	Percent	3.19	0.00	3.19	1.00	0.80	0.00	0.60	0.20	8.98
	Row Pct	35.56	0.00	35.56	11.11	8.89	0.00	6.67	2.22	
	Col Pct	6.61	0.00	17.39	6.33	10.53	0.00	18.75	33.33	
Greater than 10,000	Frequency	2	0	7	0	1	0	0	0	10
	Percent	0.40	0.00	1.40	0.00	0.20	0.00	0.00	0.00	2.00
	Row Pct	20.00	0.00	70.00	0.00	10.00	0.00	0.00	0.00	
	Col Pct	0.83	0.00	7.61	0.00	2.63	0.00	0.00	0.00	
Total	Frequency	242	11	92	79	38	20	16	3	501
	Percent	48.30	2.20	18.36	15.77	7.58	3.99	3.19	0.60	100.00

Test independence of spill size and cause

The FREQ Procedure

Statistics for Table of Size by Cause

Statistic	DF	Value	Prob
Chi-Square	35	69.8063	0.0004
Likelihood Ratio Chi-Square	35	74.5435	0.0001
Mantel-Haenszel Chi-Square	1	7.1462	0.0075
Phi Coefficient		0.3733	
Contingency Coefficient		0.3497	
Cramer's V		0.1669	

WARNING: 60% of the cells have expected counts less than 5. Chi-Square may not be a valid test.

Sample Size = 501

The data strongly indicates the hypothesis that cause and spill size are independent must be rejected. Clearly, the larger the spill size is, the greater the frequency that the primary cause was corrosion. Conversely, the smaller the spill size is, the greater the frequency that the primary cause was valve/seal failure.

Conclusions regarding cause:

1. Valve/seal failure is the leading cause of all spills.
2. For large spills of volume greater than 1,000 gallons, the primary cause is corrosion with valve/seal accounting for the next largest group of spills.
3. Corrosion is a larger problem for Kuparuk River than for Prudhoe Bay.

H.4 Analysis of Spill Data by Regulatory Category

Consider the number and volume of spills by regulatory category:

Summary of Spills by Regulatory Category

Reg. Category	Total Number	Spilled	Average Volume
Facility Oil Piping	240	246,131.19	1,025.55
Flowline	71	267,102.10	3,762.00
Oil Transmission Pipeline	9	217,439.00	24,159.89
Process Piping	202	156,344.50	773.98
Storage Tank	10	247,137.00	24,713.70
Well	108	66,637.50	617.01

The average volume is extremely large for OTP and storage tank spills. However, this is due solely to the two large spills occurring in 2006. These spills were the Prudhoe Bay storage tank spill on December 19, 2006 in which 241,000 gallons were spilled, and the Prudhoe Bay oil transmission pipeline spill on March 2 of that same year in which 212,000 gallons were spilled. Removing these two extreme outliers from the data set suggests a much different picture.

Summary of Spills by Regulatory Category - outliers removed

Reg. Category	Number	Total Spilled	Average Volume
Facility Oil Piping	240	246,131.19	1,025.55
Flowline	71	267,102.10	3,762.00
Oil Transmission Pipeline	8	5,187.00	648.38
Process Piping	202	156,344.50	773.98
Storage Tank	9	6,099.00	677.67
Well	108	66,637.50	617.01

When looked at in this way, it is apparent that, in general, storage tank spills account for a very small number of spills and generally a low average volume. OTP spills, when excluding the outlier, are found to be few in number and moderate in size. Care must be taken to avoid erroneous conclusions based upon the incorrect assumption that the mean value reported in the first of these two tables is a good indicator of central tendency for the variable.

It would be important to know whether there is a time/regulatory category effect:

Consider an ANCOVA analysis with number of spills as the dependent variable, year as a continuous independent variable, and regulatory category as an independent categorical variable.

The GLM Procedure

Dependent Variable: number number

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	11	3310.500183	300.954562	34.45	<.0001
Error	72	629.059341	8.736935		
Corrected Total	83	3939.559524			

R-Square	Coeff Var	Root MSE	number Mean
0.840322	40.11143	2.955831	7.369048

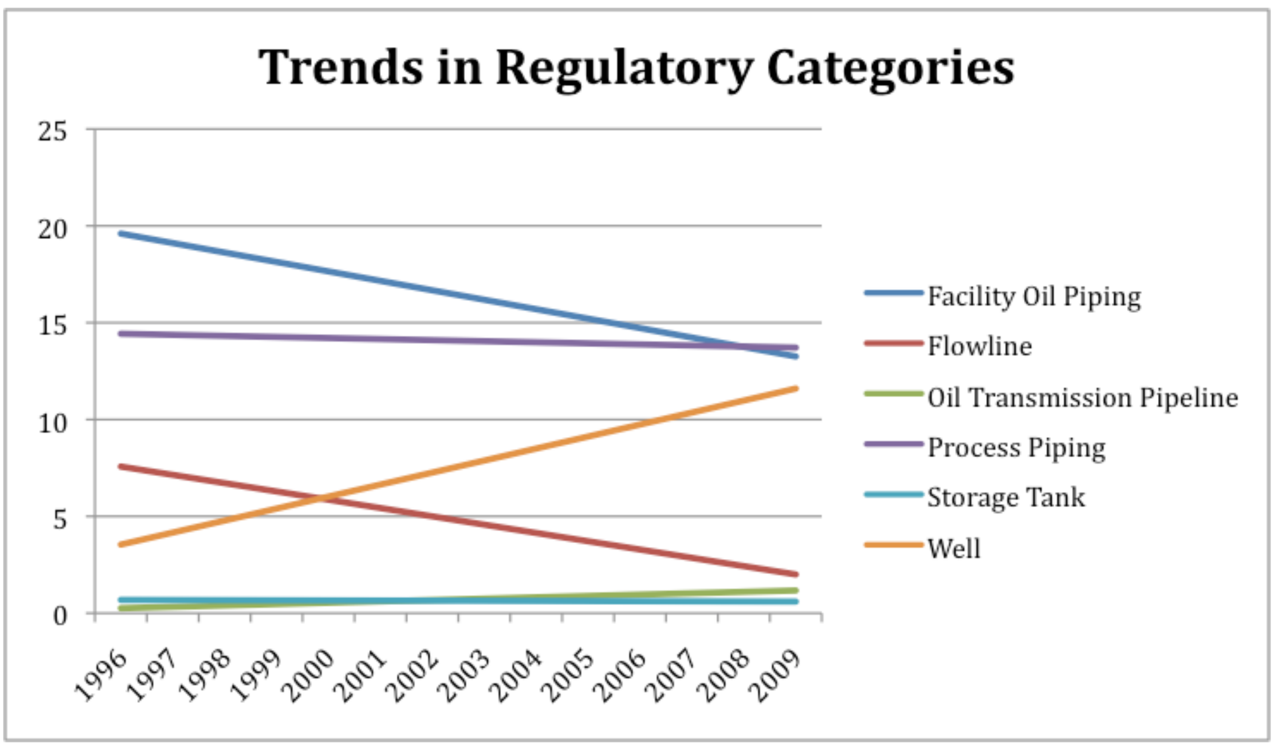
Source	DF	Type I SS	Mean Square	F Value	Pr > F
Regulatory_Category	5	3125.345238	625.069048	71.54	<.0001
SpillYear	1	3.143040	3.143040	0.36	0.5505
SpillYear*Regulatory	5	182.011905	36.402381	4.17	0.0022

Source	DF	Type III SS	Mean Square	F Value	Pr > F
Regulatory_Category	5	182.9280613	36.5856123	4.19	0.0021
SpillYear	1	3.1430403	3.1430403	0.36	0.5505
SpillYear*Regulatory	5	182.0119047	36.4023809	4.17	0.0022

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	-1233.538461 B	392.4300572	-3.14	0.0024

Regulatory_Category Facility Oil Piping	2227.010988	B	554.9799092	4.01	0.0001
Regulatory_Category Flowline	2096.538461	B	554.9799092	3.78	0.0003
Regulatory_Category Oil Transmission Pipeline	1093.417582	B	554.9799091	1.97	0.0527
Regulatory_Category Process Piping	1357.637362	B	554.9799091	2.45	0.0169
Regulatory_Category Storage Tank	1247.384615	B	554.9799091	2.25	0.0277
Regulatory_Category Well	0.000000	B	.	.	.
SpillYear	0.619780	B	0.1959697	3.16	0.0023
SpillYear*Regulatory Facility Oil Piping	-1.107692	B	0.2771430	-4.00	0.0002
SpillYear*Regulatory Flowline	-1.048352	B	0.2771430	-3.78	0.0003
SpillYear*Regulatory Oil Transmission Pipeline	-0.549451	B	0.2771430	-1.98	0.0512
SpillYear*Regulatory Process Piping	-0.674725	B	0.2771430	-2.43	0.0174
SpillYear*Regulatory Storage Tank	-0.626374	B	0.2771430	-2.26	0.0268
SpillYear*Regulatory Well	0.000000	B	.	.	.

The p-value of 0.0022 for the test of the year regulatory category interaction indicates that not only is the number of spills dependent upon regulatory category, but also the slopes of the best fit lines are different for the categories. In short, there are significant linear trends over time within at least some regulatory categories. The graph below helps to illustrate that while the overall number of spills has remained essentially constant over time, the reason is that significant decreases in the number of facility oil piping and flowline spills are being offset by a significant increase in the number of well spills.



This graph suggests some interesting trends. To study them further the data set was broken into subsets by regulatory category. A discussion of each follows.

H.4.1 Flowlines

Flowline spills are divided by service category into three subcategories: Operational Activities, Three Phase, and Produced Water. Consider summary information for the total spill line flows and for each of these 3 categories:

Summary of Flowline spills

Year	Number of Spills	Total Volume	Average Volume
1995	3	574	191.33
1996	8	11,295	1,411.88
1997	8	7,520	940.00
1998	5	75,686	15,137.20
1999	9	8,903	989.22
2000	4	1,285	321.25
2001	3	92,822	30,940.67
2002	4	1,067	266.75
2003	7	6,292	898.86
2004	5	5,687	1,137.40
2005	4	1,343	335.75
2006	4	995	248.75
2007	3	5,691	1,897.00
2008	1	0	0.10
2009	3	47,942	15,980.67

Summary of Flowline Spills by Year and Sub-Category

Spill Year	Sub Category	Number of Spills	Volume of spills	Average Volume
1996	3P FL	4	78	19.50
1997	3P FL	3	2,009	669.67
1998	3P FL	0	0	0.00
1999	3P FL	0	0	0.00
2000	3P FL	2	635	317.50
2001	3P FL	1	420	420.00
2002	3P FL	2	970	485.00
2003	3P FL	4	6,093	1523.25
2004	3P FL	2	155	77.50
2005	3P FL	1	16	16.00
2006	3P FL	1	700	700.00
2007	3P FL	2	5,586	2793.00
2008	3P FL	1	0	0.10
2009	3P FL	3	47,942	15980.67
1996	PW FL	2	2,271	1135.50
1997	PW FL	0	0	0.00
1998	PW FL	2	73,500	36750.00
1999	PW FL	1	6,300	6300.00
2000	PW FL	0	0	0.00
2001	PW FL	1	92,400	92400.00
2002	PW FL	0	0	0.00
2003	PW FL	1	5	5.00
2004	PW FL	1	5,250	5250.00
2005	PW FL	0	0	0.00
2006	PW FL	1	5	5.00
2007	PW FL	0	0	0.00
2008	PW FL	0	0	0.00
2009	PW FL	0	0	0.00
1996	OA FL	2	8,946	4473.00
1997	OA FL	5	5,511	1102.20
1998	OA FL	3	2,186	728.67
1999	OA FL	8	2,603	325.38
2000	OA FL	2	650	325.00
2001	OA FL	1	2	2.00
2002	OA FL	2	97	48.50
2003	OA FL	2	194	97.00
2004	OA FL	2	282	141.00
2005	OA FL	3	1,327	442.33
2006	OA FL	2	290	145.00
2007	OA FL	1	105	105.00
2008	OA FL	0	0	0.00
2009	OA FL	0	0	0.00

Even for Flowline spills, for which there were no spills over 100,000 gallons, the distribution of spill volume is still exceedingly non-normal. Two spills within the sub-category 'Produced Water' dominate the data. The other factor that stands out as exceptional is the large number of maintenance activity spills in 1999.

A 2-way ANOVA test was run to determine whether or not the number of spills is effected by year and/or the three sub-categories. The null hypothesis is that the number of spills is independent of year and sub-category.

The GLM Procedure

Dependent Variable: Number Number

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	3	35.2414955	11.7471652	6.49	0.0013
Error	36	65.1585045	1.8099585		
Corrected Total	39	100.4000000			

R-Square	Coeff Var	Root MSE	Number Mean
0.351011	79.13806	1.345347	1.700000

Source	DF	Type I SS	Mean Square	F Value	Pr > F
Sub_cat	2	29.22142857	14.61071429	8.07	0.0013
SpillYear	1	6.02006689	6.02006689	3.33	0.0765

Source	DF	Type III SS	Mean Square	F Value	Pr > F
Sub_cat	2	26.54960892	13.27480446	7.33	0.0021
SpillYear	1	6.02006689	6.02006689	3.33	0.0765

Parameter		Estimate	Standard Error	t Value	Pr > |t|
Intercept		203.5693980 B	110.1138652	1.85	0.0727
Sub_cat	3P FL	-0.7925227 B	0.5321084	-1.49	0.1451
Sub_cat	PW FL	-2.0068084 B	0.5321084	-3.77	0.0006
Sub_cat	OA FL	0.0000000 B	.	.	.
SpillYear		-0.1003344	0.0550153	-1.82	0.0765

NOTE: The X'X matrix has been found to be singular, and a generalized inverse was used to solve the normal equations. Terms whose estimates are followed by the letter 'B' are not uniquely estimable.

Test whether the mean number of spills each year is equal by Sub-cat

The GLM Procedure

Level of Sub_cat	N	Number Mean	Number Std Dev	SpillYear Mean	SpillYear Std Dev
3P FL	14	1.85714286	1.29241235	2002.50000	4.18330013
PW FL	14	0.64285714	0.74494634	2002.50000	4.18330013
OA FL	12	2.75000000	1.95982374	2001.50000	3.60555128

The conclusion, with a p-value of 0.0013, is that the ANOVA model that considers year and subcategory is significant. This appears to come primarily from the effect of sub-category. Operational activities lead to, on average, 2.75 flowline spills per year which is more than four times as many spills as result from produced water flowlines. A separate test of whether or not there is an interaction between year and sub-category revealed that there was not.

The volume spilled from produced water lines appears to be significantly higher in the table above. A second 2-way ANOVA test to consider whether or not year and sub-category were significant determinants of the volume spilled:

Two-way ANOVA to test effect of Year and Sub-category on Volume spilled

The GLM Procedure

Dependent Variable: Volume Volume

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	3	976432525	325477508	0.85	0.4749
Error	36	13757258513	382146070		
Corrected Total	39	14733691038			

R-Square	Coeff Var	Root MSE	Volume Mean
0.066272	293.3808	19548.56	6663.203

Source	DF	Type I SS	Mean Square	F Value	Pr > F
Sub_cat	2	870607837.4	435303918.7	1.14	0.3314
SpillYear	1	105824687.5	105824687.5	0.28	0.6020

Source	DF	Type III SS	Mean Square	F Value	Pr > F
Sub_cat	2	914498327.4	457249163.7	1.20	0.3140
SpillYear	1	105824687.5	105824687.5	0.28	0.6020

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	843823.0658 B	1600008.915	0.53	0.6012
Sub_cat 3P FL	3185.8332 B	7731.798	0.41	0.6828
Sub_cat PW FL	11409.1832 B	7731.798	1.48	0.1487
Sub_cat OA FL	0.0000 B	.	.	.
SpillYear	-420.6713	799.400	-0.53	0.6020

Two-way ANOVA to test effect of Year and Sub-category on Volume spilled

The GLM Procedure

Level of Sub_cat	N	Volume Mean	Volume Std Dev	SpillYear Mean	SpillYear Std Dev
3P FL	14	4614.5786	12633.0448	2002.50000	4.18330013
PW FL	14	12837.9286	30006.4689	2002.50000	4.18330013
OA FL	12	1849.4167	2752.1440	2001.50000	3.60555128

Interestingly enough, with a p-value of 0.4749, there is no evidence that supports rejecting the null hypothesis that volume spilled is independent of year and sub-category. Neither independent variable was significant.

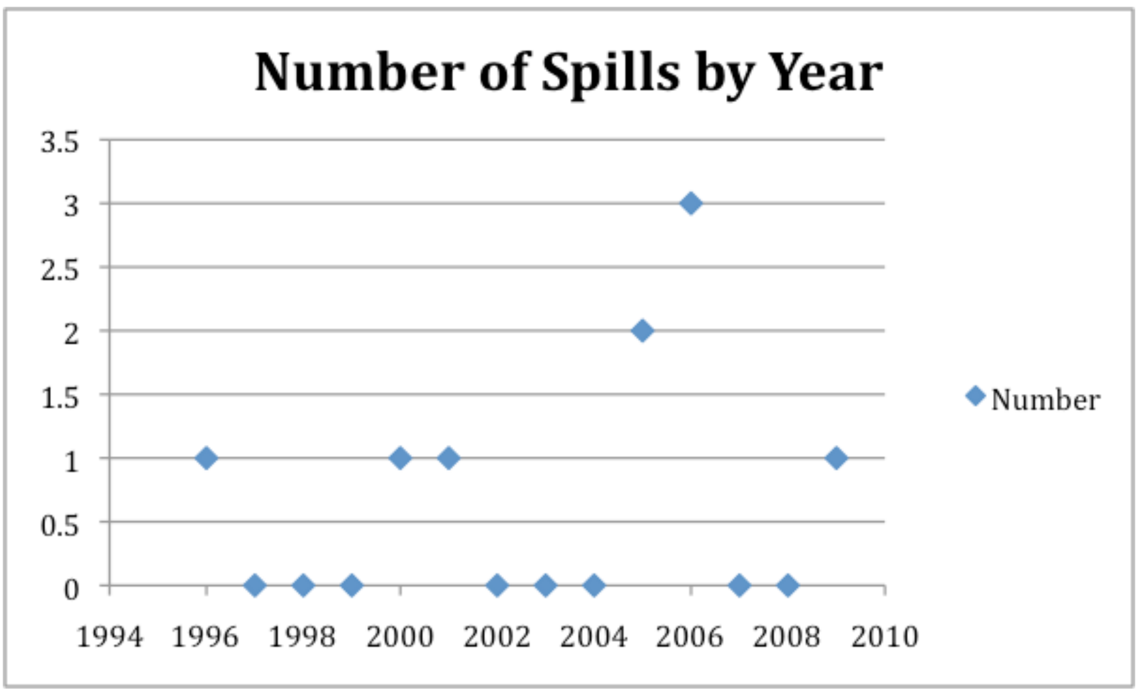
H.4.2 Oil transmission pipelines

Consider the number and volume of spills by year:

Summarize Oil Transmission Piping Spills by Year

Spill Year	Quantity Spilled	Number of Spills
1996	84.00	1
2000	2.00	1
2001	1.00	1
2005	5.00	2
2006	217,342.00	3
2009	5.00	1

Below is a scatter plot of the observations:



It appears that a best fit would be upwardly sloping. However, the sample size is quite small, and this would most likely make the power of the analysis very low. Still, the regression was run:

Consider number of spills vs time

The GLM Procedure

Dependent Variable: Number Number

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	0.58131868	0.58131868	0.66	0.4337
Error	12	10.63296703	0.88608059		
Corrected Total	13	11.21428571			

R-Square	Coeff Var	Root MSE	Number Mean
0.051837	146.4273	0.941319	0.642857

Source	DF	Type I SS	Mean Square	F Value	Pr > F
SpillYear	1	0.58131868	0.58131868	0.66	0.4337

Source	DF	Type III SS	Mean Square	F Value	Pr > F
SpillYear	1	0.58131868	0.58131868	0.66	0.4337

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	-100.5824176	124.9738977	-0.80	0.4366
SpillYear	0.0505495	0.0624088	0.81	0.4337

The slope is positive indicating an increasing number of spills over time, but with a p-value of 0.4337 the overall conclusion is that year does not have a significant effect on the number of OTP spills.

H.4.3 Facility Oil Piping

Consider the quantity spilled and number of spills by year:

Summarize Facility Oil Piping Spills by Year

Spill Year	Quantity Spilled	Number of Spills
1996	1,668.00	22
1997	4,235.00	18
1998	4,202.00	25
1999	6,523.00	11
2000	2,333.00	15
2001	2,983.00	17
2002	7,756.00	16
2003	5,714.00	21
2004	3,227.00	19
2005	2,778.00	10
2006	1,873.00	14
2007	39,293.50	5
2008	159,642.13	23
2009	2,565.56	14

There were obviously larger than normal volume spills occurring in 2007 and 2008. The graph above where all regulatory categories had been included suggested that there was a decrease in the number of facility oil piping spills over time. A linear regression on the reduced data set can check this.

Consider number of spills vs time

The GLM Procedure

Dependent Variable: N_spill Number of Spills

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F

Model	1	54.1582418	54.1582418	1.92	0.1915
Error	12	339.2703297	28.2725275		
Corrected Total	13	393.4285714			

R-Square	Coeff Var	Root MSE	N_spill Mean
0.137657	32.36551	5.317192	16.42857

Source	DF	Type I SS	Mean Square	F Value	Pr > F
SpillYear	1	54.15824176	54.15824176	1.92	0.1915

Source	DF	Type III SS	Mean Square	F Value	Pr > F
SpillYear	1	54.15824176	54.15824176	1.92	0.1915

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	993.4725275	705.9354990	1.41	0.1847
SpillYear	-0.4879121	0.3525264	-1.38	0.1915

While the slope of the best fit line is negative, indicating a decrease in number with time, the p-value of 0.1915 indicates that there is not sufficient evidence to reject the null hypothesis that the number of spills is independent of time.

H.4.4 Process Piping

Consider a summary of the number and volume of spills by year for process piping:

Summarize Process Piping Spills by Year

Spill Year	Quantity Spilled	Number of Spills
1996	13,742.00	16
1997	5,578.00	17
1998	4,176.00	15
1999	1,202.00	12
2000	8,656.00	13
2001	6,629.00	12
2002	12,415.00	12
2003	12,194.00	10
2004	33,300.00	11
2005	6,477.00	17
2006	7,261.00	21
2007	9,572.00	19
2008	2,544.50	15
2009	19,593.00	7

The data looks very consistent over time. A regression of the number of spills vs time can verify this:

Consider number of spills vs time

The GLM Procedure

Dependent Variable: N_spill Number of Spills

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	0.6868132	0.6868132	0.04	0.8360
Error	12	184.2417582	15.3534799		
Corrected Total	13	184.9285714			

R-Square	Coeff Var	Root MSE	N_spill Mean
0.003714	27.84615	3.918352	14.07143

Source	DF	Type I SS	Mean Square	F Value	Pr > F
SpillYear	1	0.68681319	0.68681319	0.04	0.8360

Source	DF	Type III SS	Mean Square	F Value	Pr > F
SpillYear	1	0.68681319	0.68681319	0.04	0.8360

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	124.0989011	520.2188874	0.24	0.8155
SpillYear	-0.0549451	0.2597842	-0.21	0.8360

There is no evidence to suggest rejecting the null hypothesis that the number of process piping spills is constant over time.

H.4.5 Wells

Consider a summary of the number of spills and quantity spilled by year:

Summarize Well Spills by Year

Spill Year	Quantity Spilled	Number of Spills
1996	54.00	4
1997	765.00	3
1998	72.00	5
1999	14.00	3
2000	301.00	8
2001	36.00	6
2002	11,816.00	5
2003	232.00	11
2004	279.00	10
2005	51,576.00	11
2006	802.00	12
2007	26.50	8
2008	335.50	8
2009	303.50	12

In this case the data suggests a significant upward trend. Consider the regression:

Consider number of spills vs time

The GLM Procedure

Dependent Variable: N_spill Number of Spills

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	87.3890110	87.3890110	20.15	0.0007
Error	12	52.0395604	4.3366300		
Corrected Total	13	139.4285714			

R-Square	Coeff Var	Root MSE	N_spill Mean
0.626765	27.50416	2.082458	7.571429

Source	DF	Type I SS	Mean Square	F Value	Pr > F
SpillYear	1	87.38901099	87.38901099	20.15	0.0007

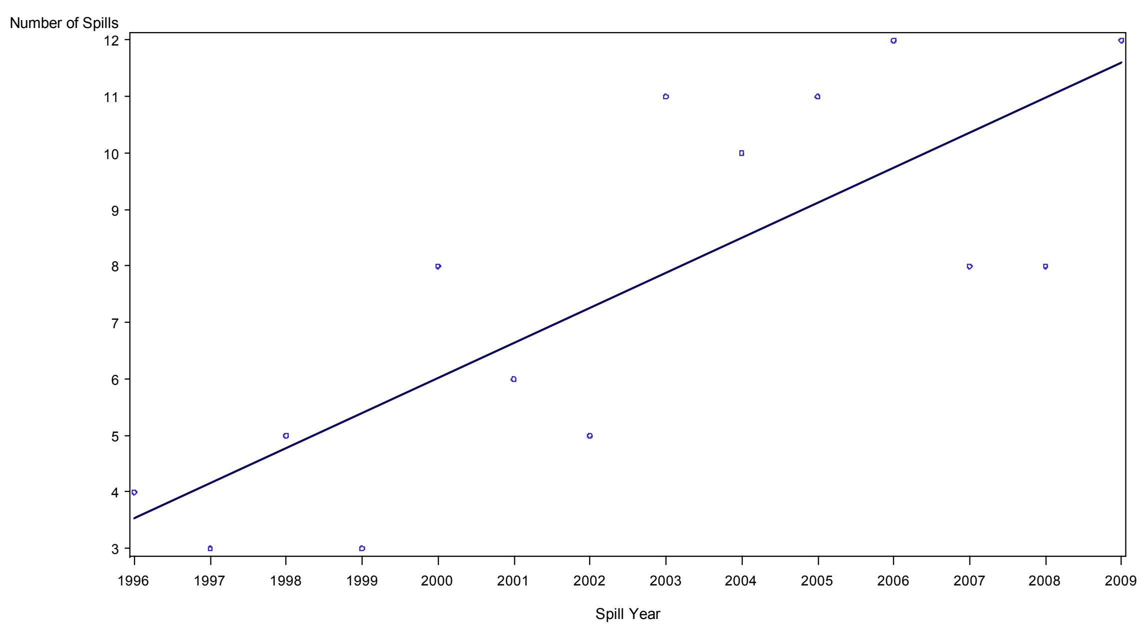
Source	DF	Type III SS	Mean Square	F Value	Pr > F
SpillYear	1	87.38901099	87.38901099	20.15	0.0007

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	-1233.538462	276.4769253	-4.46	0.0008
SpillYear	0.619780	0.1380656	4.49	0.0007

Once again, the sample size is small and thus the power of the analysis is low. However, at a p-value of 0.0007 there is evidence to reject a null hypothesis that the number of oil spills is constant over time. The evidence suggests an increase in the number by 0.6 spills per year.

The graph is shown below:

Scatter Plot of Number of Well Spills vs Year



H.4.6 Above ground oil storage tanks

Consider the summary of the number of spills and quantity spilled for oil storage tanks:

Summarize Storage Tank Spills by Year

Spill Year	Quantity Spilled	Number of Spills
1998	3,370.00	2
2001	2,600.00	1
2002	104.00	3
2003	20.00	1
2006	241,038.00	1
2009	3.00	1

It is clear that the number of spills is not increasing. However, the largest spill considered in this study was an oil storage tank spill in 2006, and so the potential risk of these spills is clearly illustrated.

H.5 Comparison of Leak Rates

H.5.1 Leak Rates Based on Total Throughput

Consider the amounts produced and spilled at each oil field:

Total oil and water produced and spilled by Oil Field

Oil Field	Oil Produced	Water Produced	Total Produced	Total Spilled	Spill ratio (ppm)
Badami	5,198,420	0	5,198,420	295	56.748
Colville River, Alpine	351,632,828	30,977,761	382,610,589	5,240	13.695
Endicott	169,210,549	963,111,138	1,132,321,687	6,661	5.883
Kuparuk River	1,123,177,607	2,775,282,031	3,898,459,638	373,020	95.684
Milne Point	235,844,750	489,873,571	725,718,321	73,636	101.467
North Star	141,811,174	28,679,622	170,490,796	98	0.575
Prudhoe Bay	2,987,017,635	6,549,833,660	9,536,851,295	741,841	77.787

The field with the largest ratio of total spilled to total produced is Milne Point (101.5 gallons spilled per 1,000,000 gallons produced), followed closely by Kuparuk River (95.7 bbl/mm bbl). The field with the smallest spill ratio is North Star. Endicott also has a very low spill ratio, and in contrast to North Star, it is a significant producer.

It has been noted before that quantity spilled is not a good indicator of total performance because infrequently occurring large volume spills bias the data. Therefore, consider the number of spills by production volume:

Total oil and water produced and number of spills by Oil Field

Oil Field	Oil Produced	Water Produced	Total Produced	Number of Spills	Spill ratio (x 1,000,000)
Badami	5,198,420	0	5,198,420	4	0.769
Colville River, Alpine	351,632,828	30,977,761	382,610,589	5	0.013
Endicott	169,210,549	963,111,138	1,132,321,687	10	0.009
Kuparuk River	1,123,177,607	2,775,282,031	3,898,459,638	138	0.035
Milne Point	235,844,750	489,873,571	725,718,321	41	0.056
North Star	141,811,174	28,679,622	170,490,796	4	0.023
Prudhoe Bay	2,987,017,635	6,549,833,660	9,536,851,295	438	0.046

Looking at the situation in this manner reveals that Badami has the worst ratio of number of spills to total production volume. However, it is a minor producer. Of the large producers, Endicott continues to stand out due to its exceptionally low ratio of 0.009 spills per 1 million total gallons produced. The highest ratio among those fields producing more than 1 billion total gallons is Prudhoe Bay, followed by Kuparuk River.

It is also helpful to look at the ratio of number of spills to oil produced:

Total oil produced and number of spills by Oil Field

Oil Field	Oil Produced	Water Produced	Total Produced	Number of Spills	Spill ratio (x 1,000,000)
Badami	5,198,420	0	5,198,420	4	0.769
Colville River, Alpine	351,632,828	30,977,761	382,610,589	5	0.014
Endicott	169,210,549	963,111,138	1,132,321,687	10	0.059
Kuparuk River	1,123,177,607	2,775,282,031	3,898,459,638	138	0.123
Milne Point	235,844,750	489,873,571	725,718,321	41	0.174
North Star	141,811,174	28,679,622	170,490,796	4	0.028
Prudhoe Bay	2,987,017,635	6,549,833,660	9,536,851,295	438	0.147

The Badami field, where evidently no water is produced at the wells, continues to have a very high ratio of number of spills to oil production. Endicott has a high water to oil ratio. However, even when just oil production is considered, it still has a low ratio of number of spills to production.

The data was tabulated by year in order to check for time trends. A two-way ANOVA was run with the ratio of number of yearly spills to production as the dependent variable.

Analysis of the effects of oil field and spill year on spills per production ratio

The GLM Procedure

Dependent Variable: Num_ratio Number spill ratio

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	7	3.43028378	0.49004054	3.04	0.0069
Error	80	12.89456695	0.16118209		
Corrected Total	87	16.32485073			

R-Square	Coeff Var	Root MSE	Num_ratio Mean
0.210127	330.2455	0.401475	0.121569

Source	DF	Type I SS	Mean Square	F Value	Pr > F
Oil_Field	6	3.38601292	0.56433549	3.50	0.0040
SpillYear	1	0.04427087	0.04427087	0.27	0.6017

Source	DF	Type III SS	Mean Square	F Value	Pr > F
Oil_Field	6	3.41353932	0.56892322	3.53	0.0038
SpillYear	1	0.04427087	0.04427087	0.27	0.6017

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	11.54383385 B	21.93664273	0.53	0.6002
Oil_Field Badami	0.61650249 B	0.16931608	3.64	0.0005
Oil_Field Colville River, Alpine	-0.02175683 B	0.16617480	-0.13	0.8962
Oil_Field Endicott	-0.03873657 B	0.14659790	-0.26	0.7923
Oil_Field Kuparuk River	-0.01156534 B	0.14659790	-0.08	0.9373
Oil_Field Milne Point	0.00962792 B	0.14659790	0.07	0.9478
Oil_Field North Star	0.23648082 B	0.17243881	1.37	0.1741
Oil_Field Prudhoe Bay	0.00000000 B	.	.	.
SpillYear	-0.00574251	0.01095724	-0.52	0.6017

NOTE: The X'X matrix has been found to be singular, and a generalized inverse was used to solve the normal equations. Terms whose estimates are followed by the letter 'B' are not uniquely estimable.

The conclusion is that the number of spills ratio is dependent upon the oil field (p-value of 0.0038) but not dependent upon the year (p-value of 0.6017).

The mean yearly ratio of number of spills per production volume is shown below:

Analysis of the effects of oil field and spill year on spills per production ratio

The GLM Procedure

Level of Oil_Field	N	Num_ratio Mean	Num_ratio Std Dev	SpillYear Mean	SpillYear Std Dev
Badami	9	0.66191452	0.99935358	2002.33333	3.16227766
Colville River, Alpine	10	0.01121309	0.01203998	2004.50000	3.02765035
Endicott	15	0.00858963	0.00958294	2002.00000	4.47213595
Kuparuk River	15	0.03576086	0.01579235	2002.00000	4.47213595
Milne Point	15	0.05695412	0.03877521	2002.00000	4.47213595
North Star	9	0.26657949	0.78414576	2005.00000	2.73861279
Prudhoe Bay	15	0.04732620	0.01456395	2002.00000	4.47213595

H.5.2 Leak Rates Based on Pipeline Length

There exists a group of pipeline spills for which data on the pipeline is available. This data is listed below:

Details for pipeline spills where pipe data is available

Spill Id	Oil_field	ADEC Regulatory Cat.	Quantity Spilled	Hydraulic Length (ft)
273	Colville River, Alpine	OTP	1	180,576.00
385	Kuparuk River	FL-3 phase	4,362	10,266.00
324	Kuparuk River	FL-3 phase	40	10,983.00
277	Kuparuk River	FL-3 phase	16	7,785.00
231	Kuparuk River	FL-3 phase	4,284	10,242.00
203	Kuparuk River	FL-3 phase	0	10,266.00
1126	Kuparuk River	FL-3 phase	3	14,495.00
331	Kuparuk River	FL-3 phase	15	10,242.00
1180	Kuparuk River	FL-3 phase	1	13,629.00
256	Kuparuk River	FL-3 phase	5	10,723.00
1083	Kuparuk River	FL-3 phase	2,000	9,466.00
385	Kuparuk River	FL-Produced H2O	1,938	11,717.00
372	Kuparuk River	FL-Produced H2O	92,400	4,071.00
393	Kuparuk River	FL-Produced H2O	10,500	10,553.00
1051	Kuparuk River	FL-Produced H2O	63,000	11,717.00
376	Kuparuk River	OTP	2	48,271.00
334	Milne Point	FL-3 phase	5	32,500.00
857	Prudhoe Bay	FL-3 phase	630	5,397.05

296	Prudhoe Bay	FL-3 phase	5,250	17,672.21
674	Prudhoe Bay	FL-3 phase	2	7,604.56
176	Prudhoe Bay	FL-3 phase	10	26,477.88
381	Prudhoe Bay	FL-3 phase	5	5,455.63
193	Prudhoe Bay	FL-3 phase	1,932	16,069.67
369	Prudhoe Bay	FL-3 phase	420	7,087.84
298	Prudhoe Bay	FL-3 phase	153	11,448.87
1220	Prudhoe Bay	FL-3 phase	25	11,448.87
266	Prudhoe Bay	FL-3 phase	700	17,068.33
340	Prudhoe Bay	FL-3 phase	4	17,672.21
1182	Prudhoe Bay	FL-3 phase	30	14,930.40
1181	Prudhoe Bay	FL-3 phase	5	5,143.94
1125	Prudhoe Bay	FL-3 phase	42	6,775.17
332	Prudhoe Bay	FL-3 phase	38	33,519.78
174	Prudhoe Bay	FL-3 phase	46,000	16,436.65
234	Prudhoe Bay	FL-3 phase	1,302	26,477.88
320	Prudhoe Bay	FL-3 phase	6,000	33,519.78
1087	Prudhoe Bay	FL-3 phase	3	18,528.98
129	Prudhoe Bay	OTP	50	18,781.33
268	Prudhoe Bay	OTP	212,252	16,325.76
188	Prudhoe Bay	OTP	5	1,321.14

A couple of points to note about this data include:

1. One of the two extremely large spills, spill number 268 in the database, is included in these cases.
2. For one spill, spill number 385, two types of pipeline were listed: FL-3 phase and FL-produced water. To facilitate the analysis, the spill quantity from this spill (6,300 gallons) was weighted by pipe cross sectional area so that 4,362 gallons were assigned to the 24 inch diameter FL-3 phase pipe and 1,938 gallons were assigned to the 16 inch FL-produced water pipe.

This data summarizes as follows where mean length refers to the average length of the piping in which a spill occurred:

Summary of pipeline spills by oil field and regulatory category

Oil field	ADEC Regulatory Cat.	Total Spilled	Number of Spills	Mean Hydraulic Length
Colville River, Alpine	OTP	1	1	180,576.0
Kuparuk River	FL-3 phase	10,726	10	10,809.7
Kuparuk River	FL-Produced H2O	167,838	4	9,514.5
Kuparuk River	OTP	2	1	48,271.0
Milne Point	FL-3 phase	5	1	32,500.0
Prudhoe Bay	FL-3 phase	62,551	19	15,722.9
Prudhoe Bay	OTP	212,307	3	12,142.7

This leads to the following observations:

1. The large Prudhoe Bay spill overwhelms the data making averages a meaningless quantity.
2. The largest number of spills occur in pipelines classified as FL-3 phase, accounting for 29 of the 39 spills listed (74.4%). OTP spills accounted for 12.8% of the spills, and FL-produced water accounted for 10.3% of the spills.
3. Colville River and Milne each had one pipeline spill. Together this accounts for

approximately 5% of the spills. Kuparuk River had 38.5% of the spills and Prudhoe Bay had 56.4% of the spills.

4. Most spills occur in sections of piping of mean hydraulic length of roughly 11,000 to 16,000 feet.

The data can also be summarized by operator:

Summary of pipeline spills by Operator and regulatory category

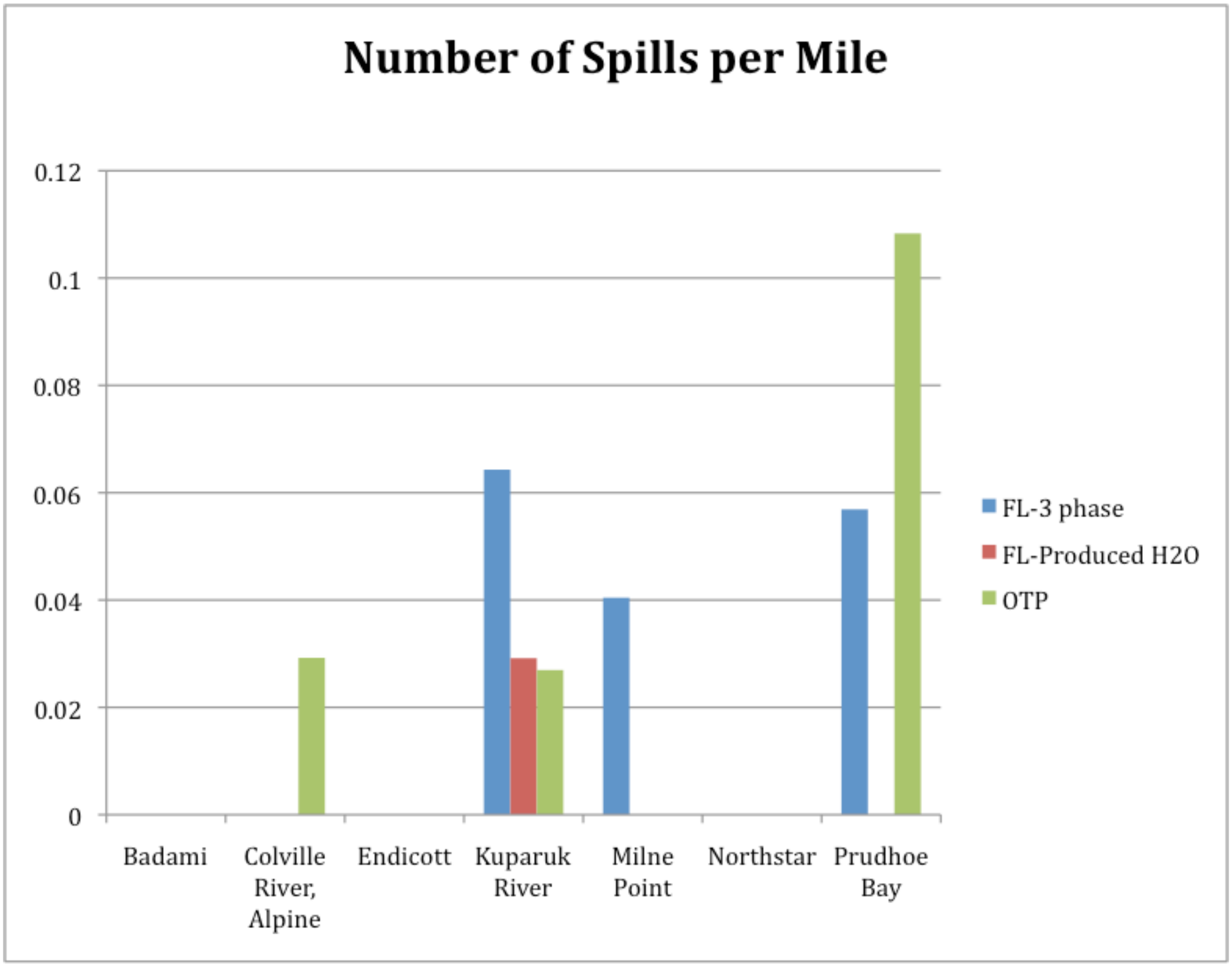
Operator	ADEC Regulatory Cat.	Total Spilled	Number of Spills	Mean Hydraulic Length
BPXA	FL-3 phase	62,556	20	16,561.8
BPXA	OTP	212,307	3	12,142.7
CP	FL-3 phase	10,726	10	10,809.7
CP	FL-Produced H2O	167,838	4	9,514.5
CP	OTP	3	2	114,423.5

BPXA has 43.8% more spills than CP, and it is responsible for 54% more spills by volume. It is also noteworthy that CP has long lengths of OTP piping with very few spills.

To analyze by total feet of pipe, the pipeline database had to first be summarized by oil field and regulatory category. This data was then combined with number of spills as follows:

Summary of Number of Spills by Length and Regulatory Category					
Oil_Field	ADEC_REG_CAT	Number of Spills	Total Hydraulic Length (ft)	Length (miles)	Number per mile
Badami	OTP	0	132,327.30	25.06	0.0000
Colville River, Alpine	FL-3 phase	0	68,890.00	13.05	0.0000
Colville River, Alpine	FL-Produced H2O	0	66,455.00	12.59	0.0000
Colville River, Alpine	OTP	1	180,576.00	34.20	0.0292
Endicott	FL-3 phase	0	18,714.77	3.54	0.0000
Endicott	FL-Produced H2O	0	18,647.76	3.53	0.0000
Endicott	OTP	0	139,417.99	26.40	0.0000
Kuparuk River	FL-3 phase	10	821,250.00	155.54	0.0643
Kuparuk River	FL-Produced H2O	4	724,067.00	137.13	0.0292
Kuparuk River	OTP	1	195,871.00	37.10	0.0270
Milne Point	FL-3 phase	1	130,564.53	24.73	0.0404
Milne Point	FL-Produced H2O	0	73,534.77	13.93	0.0000
Milne Point	OTP	0	56,897.11	10.78	0.0000
Northstar	OTP	0	92,379.36	17.50	0.0000
Prudhoe Bay	FL-3 phase	19	1,762,998.02	333.90	0.0569
Prudhoe Bay	FL-Produced H2O	0	529,312.55	100.25	0.0000
Prudhoe Bay	OTP	3	146,243.44	27.70	0.1083

Which graphically looks like the following:



An ANOVA analysis was run to test for the effect of regulatory category and length of piping on the number of spills.

Test for significance of pipe length and regulatory category

The GLM Procedure

Dependent Variable: Number_of_Spills Number of Spills

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	3	369.6233776	123.2077925	53.56	<.0001
Error	13	29.9060342	2.3004642		
Corrected Total	16	399.5294118			

R-Square	Coeff Var	Root MSE	Number_of_Spills Mean
0.925147	66.11379	1.516728	2.294118

Source	DF	Type I SS	Mean Square	F Value	Pr > F
Length__miles_	1	355.7992761	355.7992761	154.66	<.0001

ADEC_REG_CAT	2	13.8241015	6.9120508	3.00	0.0846

Source	DF	Type III SS	Mean Square	F Value	Pr > F
Length__miles_	1	272.3225372	272.3225372	118.38	<.0001
ADEC_REG_CAT	2	13.8241015	6.9120508	3.00	0.0846

Parameter		Estimate	Standard Error	t Value	Pr > |t|
Intercept		-0.648840145 B	0.58680003	-1.11	0.2889
Length__miles_		0.053386119	0.00490675	10.88	<.0001
ADEC_REG_CAT	FL-3 phase	0.981787705 B	0.97221992	1.01	0.3310
ADEC_REG_CAT	FL-Produced H2O	-1.406542878 B	0.89863335	-1.57	0.1415
ADEC_REG_CAT	OTP	0.000000000 B	.	.	.

NOTE: The X'X matrix has been found to be singular, and a generalized inverse was used to solve the normal equations. Terms whose estimates are followed by the letter 'B' are not uniquely estimable.

It is revealed that hydraulic length is very highly significant in effecting the number of spills that occur. The p-value for the test of significance is essentially zero, and the model has an R2 value of 0.925 indicating that it explains 92.5% of the total variability observed in the number of spills. In other words, length of pipe explains number of pipeline spills almost perfectly. Regulatory category only appears to have a modest effect (p-value = 0.0846).

There were too few datapoints to test 3 effects simultaneously, but a separate analysis was run to test the effect of oil field when controlling for pipe length.

Test for significance of pipe length and oil field

The GLM Procedure

Dependent Variable: Number_of_Spills Number of Spills

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	7	357.8445631	51.1206519	11.04	0.0009
Error	9	41.6848487	4.6316499		
Corrected Total	16	399.5294118			

R-Square	Coeff Var	Root MSE	Number_of_Spills Mean
0.895665	93.81066	2.152127	2.294118

Source	DF	Type I SS	Mean Square	F Value	Pr > F
Length__miles_	1	355.7992761	355.7992761	76.82	<.0001
Oil_Field	6	2.0452870	0.3408812	0.07	0.9976

Source	DF	Type III SS	Mean Square	F Value	Pr > F
Length__miles_	1	210.3151513	210.3151513	45.41	<.0001
Oil_Field	6	2.0452870	0.3408812	0.07	0.9976

Standard

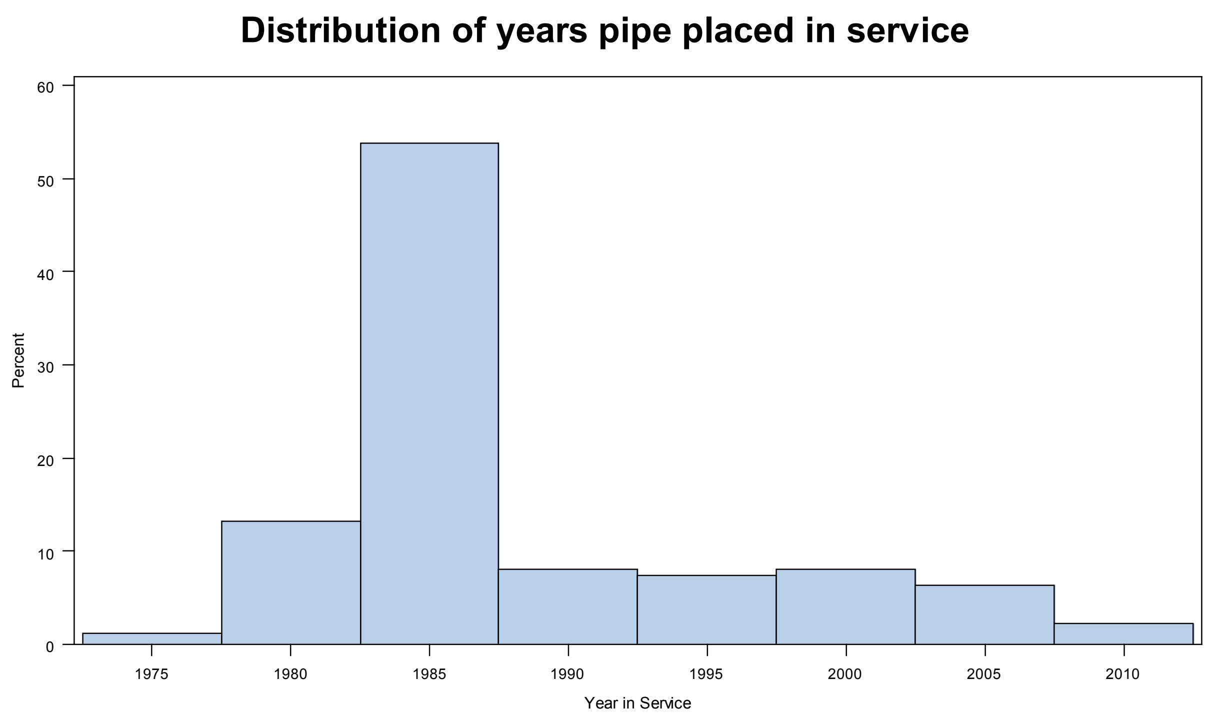
Parameter		Estimate	Error	t Value	Pr > |t|
Intercept		-1.774307861 B	1.83592601	-0.97	0.3591
Length__miles_		0.059160074	0.00877933	6.74	<.0001
Oil_Field	Badami	0.291638750 B	2.73055331	0.11	0.9173
Oil_Field	Colville River, Alpine	0.927722643 B	2.11467475	0.44	0.6712
Oil_Field	Endicott	1.114058574 B	2.15853013	0.52	0.6182
Oil_Field	Kuparuk River	0.271226325 B	1.79921116	0.15	0.8835
Oil_Field	Milne Point	1.132857923 B	2.13176082	0.53	0.6080
Oil_Field	Northstar	0.739237822 B	2.75874165	0.27	0.7948
Oil_Field	Prudhoe Bay	0.000000000 B	.	.	.

NOTE: The X'X matrix has been found to be singular, and a generalized inverse was used to solve the normal equations. Terms whose estimates are followed by the letter 'B' are not uniquely estimable.

The conclusion is that only total length of piping effects the number of spills. When this variable is controlled for, oil field is found to have no effect (p-value = 0.9976).

H.6 Leak Rates Based on Years in Service:

The pipeline database does not list the year placed in service for all piping sections. However, for those for which 'year in service' is available, we have the following distribution:



It is evident that most of the piping was placed in service in the mid-1980s. The question arises as to whether or not the probability of a given pipeline failing is a function of time that it was placed in operation. A logistic regression was designed to answer this question.

Logistic regression to test effect of pipe age on probability of failure

The LOGISTIC Procedure

Model Information

Data Set	WORK.PIPE_SUB
Response Variable	Failed
Number of Response Levels	2
Model	binary logit
Optimization Technique	Fisher's scoring

Number of Observations Read	175
Number of Observations Used	175

Response Profile

Ordered Value	Failed	Total Frequency
1	0	32
2	1	143

Probability modeled is Failed=0.

Model Convergence Status

Convergence criterion (GCONV=1E-8) satisfied.

Model Fit Statistics

Criterion	Intercept Only	Intercept and Covariates
AIC	168.494	161.471
SC	171.659	167.800
-2 Log L	166.494	157.471

Testing Global Null Hypothesis: BETA=0

Test	Chi-Square	DF	Pr > ChiSq
Likelihood Ratio	9.0238	1	0.0027
Score	7.2763	1	0.0070
Wald	6.4177	1	0.0113

Analysis of Maximum Likelihood Estimates

Parameter	DF	Estimate	Standard Error	Wald Chi-Square	Pr > ChiSq
Intercept	1	-3.8846	1.0136	14.6894	0.0001
Pipe_age	1	0.1031	0.0407	6.4177	0.0113

Odds Ratio Estimates

Effect	Point Estimate	95% Wald Confidence Limits	
Pipe_age	1.109	1.024	1.201

Association of Predicted Probabilities and Observed Responses

Percent Concordant	65.2	Somers' D	0.382

Percent Discordant	26.9	Gamma	0.415
Percent Tied	7.9	Tau-a	0.115
Pairs	4576	c	0.691

The model proved to be significant with an overall p-value for the Likelihood ratio statistic of 0.0027. The odds ratio for the test was 1.109 which is interpreted to mean that for each additional year of age, the odds that a pipeline will experience a spill increase by a factor of 1.109.

The model is:

$$\log \frac{\pi_{spill}}{1-\pi_{spill}} = -3.8846 + 0.1031(Age)$$

$$\pi_{spill} = \frac{e^{-3.8846+0.1031(Age)}}{1+e^{-3.8846+0.1031(Age)}}$$

where π_{spill} represents the probability that a pipeline will have a spill. For a pipeline that has been in service 5 years, the probability is 3.32%.

Years in Service	Probability of a spill (%)
5	3.33
10	5.45
15	8.80
20	13.91
25	21.30
30	31.18

Another logistic regression was run in which the independent variable representing the hydraulic length of a piping section was added to the model:

Logistic regression to test effect of pipe age and length on probability of failure

The LOGISTIC Procedure

Model Information

Data Set	WORK.PIPE_SUB
Response Variable	Failed
Number of Response Levels	2
Model	binary logit
Optimization Technique	Fisher's scoring

Number of Observations Read	175
Number of Observations Used	175

Response Profile

Ordered Value	Failed	Total Frequency

1	0	32
2	1	143

Probability modeled is Failed=0.

Model Convergence Status

Convergence criterion (GCONV=1E-8) satisfied.

Model Fit Statistics

Criterion	Intercept Only	Intercept and Covariates
AIC	168.494	156.065
SC	171.659	165.560
-2 Log L	166.494	150.065

Testing Global Null Hypothesis: BETA=0

Test	Chi-Square	DF	Pr > ChiSq
Likelihood Ratio	16.4291	2	0.0003
Score	13.4793	2	0.0012
Wald	11.0369	2	0.0040

Analysis of Maximum Likelihood Estimates

Parameter	DF	Estimate	Standard Error	Wald Chi-Square	Pr > ChiSq
Intercept	1	-5.2741	1.2787	17.0109	<.0001
Pipe_length	1	0.1589	0.0624	6.4795	0.0109
Pipe_age	1	0.1421	0.0478	8.8605	0.0029

Odds Ratio Estimates

Effect	Point Estimate	95% Wald Confidence Limits	
Pipe_length	1.172	1.037	1.325
Pipe_age	1.153	1.050	1.266

Association of Predicted Probabilities and Observed Responses

Percent Concordant	72.0	Somers' D	0.447
Percent Discordant	27.4	Gamma	0.450
Percent Tied	0.6	Tau-a	0.134
Pairs	4576	c	0.723

The model reveals that, with pipe age in the model, pipe length is also significant (p-value of 0.0109). When controlling for age, every additional mile of piping increases the odds of a leak by a factor of 1.172.

NORTH SLOPE
Spills Analysis